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Existing air quality conditions in portions of Wyoming, Montana, and North Dakota are described along with potential impacts of alternative levels of coal extraction, export from the region and conversion in hydroelectric power and synthetic natural gas plants within the region. The existing monitoring system and data collected are described. Assessment of the control options or technologies available to the utility industry are presented and alternative uses of coal are outlined. Discussions of the type and magnitude of pollutants, including those expected to be released are presented. In addition, various legal constraints that may limit the degree of coal conversion are discussed, and areas of critical research needs are listed.

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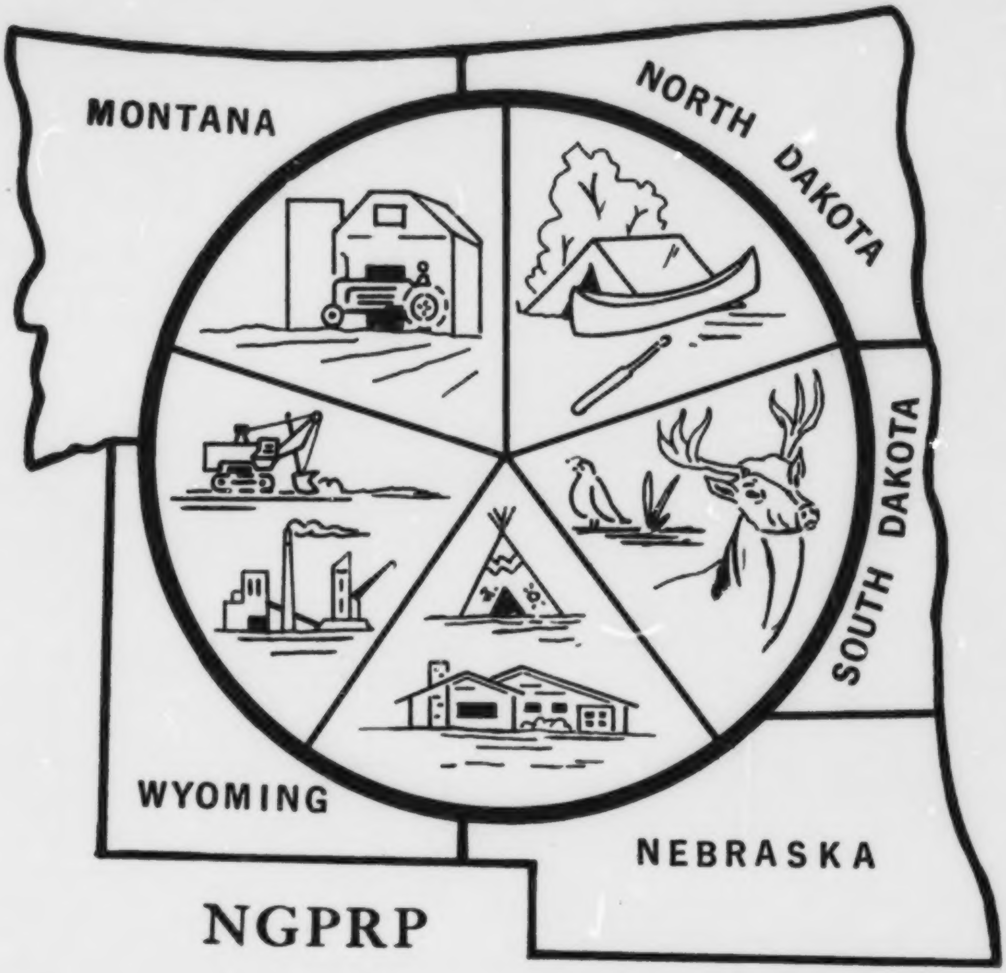
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NORTHERN GREAT PLAINS RESOURCES PROGRAM

ATMOSPHERIC ASPECTS WORK GROUP

DISCUSSION DRAFT

DECEMBER 1974

THIS REPORT WAS PREPARED PURSUANT TO A DIRECTIVE DATED OCTOBER 23, 1973, FROM THE PROGRAM MANAGER, NORTHERN GREAT PLAINS RESOURCES PROGRAM. PUBLICATION OF THE FINDINGS AND RECOMMENDATIONS HEREIN SHOULD NOT BE CONSTRUED AS REPRESENTING EITHER THE APPROVAL OR DISAPPROVAL OF THE SECRETARY OF THE INTERIOR, THE SECRETARY OF AGRICULTURE, THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY, OR THE STATES OF MONTANA, NEBRASKA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING. THE PURPOSE OF THIS REPORT IS TO PROVIDE INFORMATION AND ASSISTANCE TO THE PROGRAM MANAGEMENT TEAM IN THE PREPARATION OF THE DRAFT INTERIM REPORT ON THE NORTHERN GREAT PLAINS RESOURCES PROGRAM. THE PROGRAM MANAGEMENT TEAM IS RELEASING THIS DRAFT FOR PUBLIC USE WITHOUT CORRECTING INCONSISTENCIES OR REWRITING BECAUSE THE DELAY REQUIRED TO ACCOMPLISH THIS TASK WOULD DELAY THE TIMELY ISSUANCE OF THE REPORTS.

INTRODUCTION

The Atmospheric Aspects Work Group is one of seven work groups which are part of the Northern Great Plains Resources Program. This report summarizes knowledge and information gained by the participants of this work group. The EPA has chaired the several work group meetings which have been held over the past year and a half. EPA representatives have coordinated and written much of this document. Work group members have reviewed an early draft of this report. This report should be considered as a concensus of the work group.

Coal development activities such as coal fired power plants, coal gasification plants, and coal export mines will have an adverse impact upon the air quality of the Northern Great Plains region. The magnitude of this impact may be negligible in some areas and it may be significant in other areas. Attempts have been made in this report to quantify, where possible, these impacts. For certain parameters such as visibility degradation, only qualitative statements can be made because of the lack of applicable methodologies or tools for assessment of visibility impacts.

Extensive monitoring and data gathering activities must be performed in order to accurately track the impact upon air quality. This report describes the type of ongoing activities as well as planned activities in this area. Estimations of the local effects for the most immediate development plans are included. An assessment of the control options available to the utility industry are presented. Also, the alternative uses of coal are outlined. Discussion of the type and magnitude of pollutants, including certain trace elements, expected to be released into the atmosphere as a direct result of the projected coal development, is presented.

There are existing legal contraints which may limit the amount of coal development which may take place in the Northern Great Plains. One of the more stringent constraints may be the Federal regulations preventing significant deterioration of existing air quality.

In order to move the Nation toward a position of energy self sufficiency, the Project Independence blueprint suggests development of Western coal. This is certainly part of the entire energy program which, of course, must include energy conservation. It is possible to develop our energy resources and protect our environment. It is the objective of this work group to play its small part in this program.

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SECTION I

REGIONAL PROFILE ON ATMOSPHERIC ASPECTS OF THE NGPRP STUDY AREA

The study area of the NGPRP, as originally defined by the Regional Geology Work Group, included eastern Montana, western North Dakota, northwestern South Dakota and northeastern Wyoming, pictured in Figure I-1. Specifically, this area includes the following counties:

Montana

- Big Horn
- Carter
- Custer
- Daniels
- Dawson
- Fallon
- Garfield
- Golden Valley
- McCone
- Musselshell
- Powder River
- Prairie
- Richland
- Roosevelt
- Rosebud
- Sheridan
- Treasure
- Valley
- Wibaux
- Yellowstone

North Dakota

- Adams
- Billings
- Bottineau
- Bowman
- Burleigh
- Burke
- Divide
- Dunn
- Emmons
- Golden Valley
- Grant
- Hettinger
- Kidder
- McHenry
- McKenzie
- McLean
- Mercer
- Morton
- Montrail
- Oliver
- Pierce
- Renville
- Sheridan
- Sioux
- Slope
- Stark
- Ward
- Williams

South Dakota

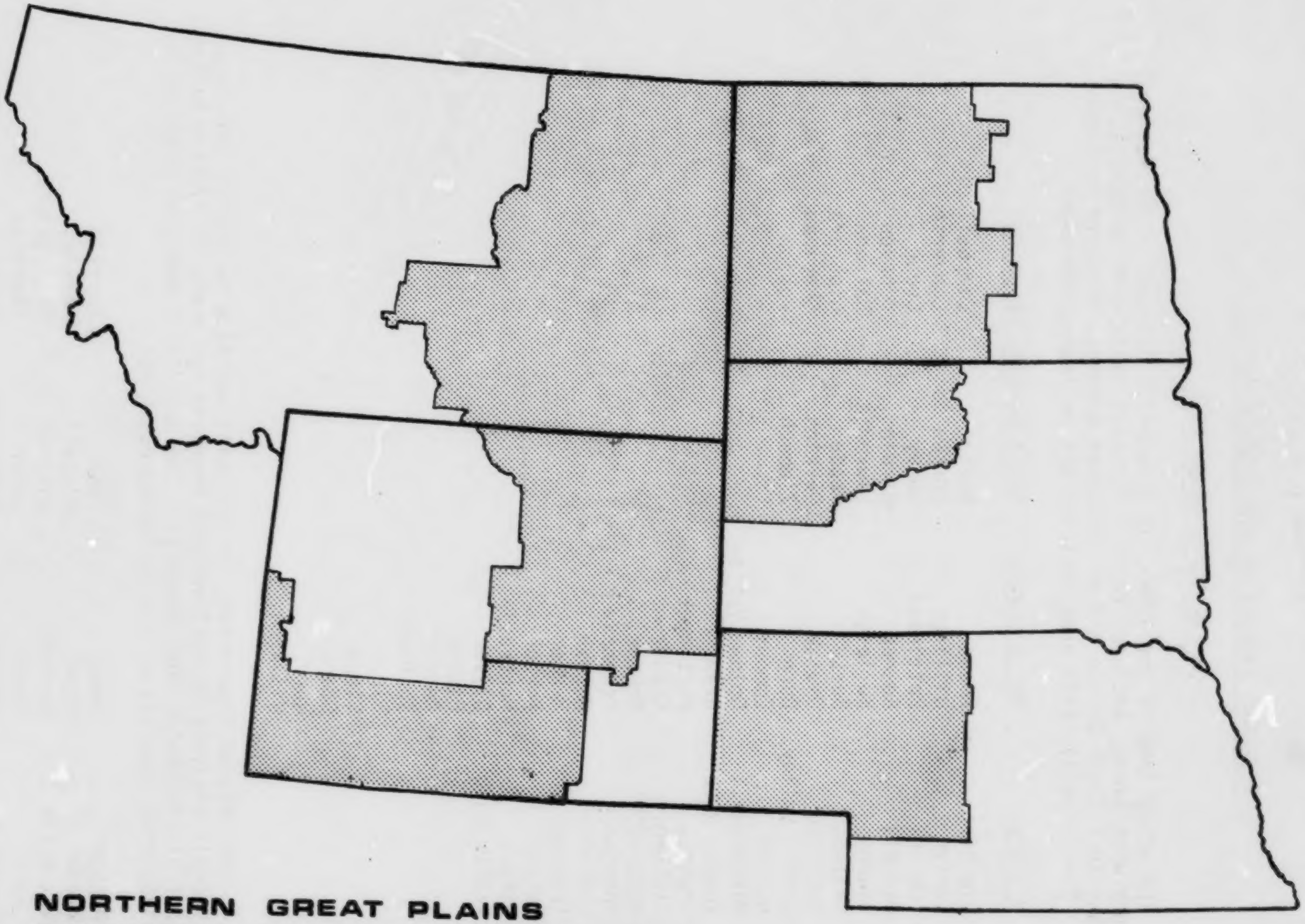
- Butte
- Corson
- Dewey
- Harding
- Lawrence
- Meade
- Perkins
- Ziebach

Wyoming

- Campbell
- Converse
- Crook
- Johnson
- Natrona
- Niobrara
- Sheridan
- Weston

As the program progressed, the decision was made to extend the Air Work Group's analysis to northwestern Nebraska and areas in Wyoming having substantial strippable coal deposits. The portion of Nebraska added to the study area consists of the following counties:

- Arthur
- Banner
- Box Butte
- Cherry
- Cheyenne
- Dawes
- Devel
- Garden
- Grant
- Hooker
- Keth
- Kimball
- Lincoln
- Logan
- McPherson
- Morrill
- Perkins
- Scottsbluff
- Sheridan
- Sioux
- Thomas



NORTHERN GREAT PLAINS RESOURCE PROGRAM STUDY AREA

Figure I-1

The Wyoming additions include Lincoln, Sweetwater, Unita and Carbon Counties. Figure I-1 includes the additional Nebraska and Wyoming study areas.

All of the major coal deposits are prime candidates for early development. Figure I-1a shows the existing and proposed power plants and the proposed gasification plants in the study area. Policy makers should have the information needed to evaluate the environmental consequences at each area of concern.

The information presented in Section I is the accumulation of historical data of four types: 1) ambient air quality data which consists of particulate, gas and trace element concentrations; 2) topography of the study area showing slope and local topographic relief; 3) meteorological data, collected primarily by the National Weather Service; and 4) State emission inventories which indicate the location of point sources and the magnitude of the emissions from these sources.

1.1 AMBIENT AIR QUALITY DATA

1.1.1 Ambient Air Quality Standards

Under the provisions of the Clean Air Act, as amended in 1970, the Administrator of the Environmental Protection Agency (EPA) is required to promulgate air quality standards for those pollutants having available criteria documenting the pollutants' adverse effects. From these documents, the National Ambient Air Quality Standards (NAAQS) have been promulgated for six pollutants as indicated in Table I-1. Table I-1 lists a primary and secondary standard for each pollutant. The former is designed to protect public health and must be met by mid 1975, while the latter is designed to protect welfare and must be met within a reasonable time thereafter.

In the September 14, 1973 Federal Register, the Administrator of EPA published notice of the revocation of the annual secondary SO_2 standard of 60 $\mu g/m^3$ (micrograms per cubic meter) and the 24 hour maximum concentration of 260 $\mu g/m^3$ used as a guide in assessing the State implementation plans to achieve the annual standard. This decision was based on a reevaluation of existing data which indicated a lack of conclusive evidence on the relationship between long-term SO_2 concentrations (24 hr., annual) and adverse impacts on the welfare of the public (i.e., effects on vegetation, crops, soils, water, property, visibility, etc.).

1.1.2 National Air Quality

National air quality averages and trends are presented below to provide a mechanism of comparison for the NGPRP air quality data.

EXISTING AND PROPOSED ENERGY GENERATION FACILITIES IN THE NGPRP STUDY AREA

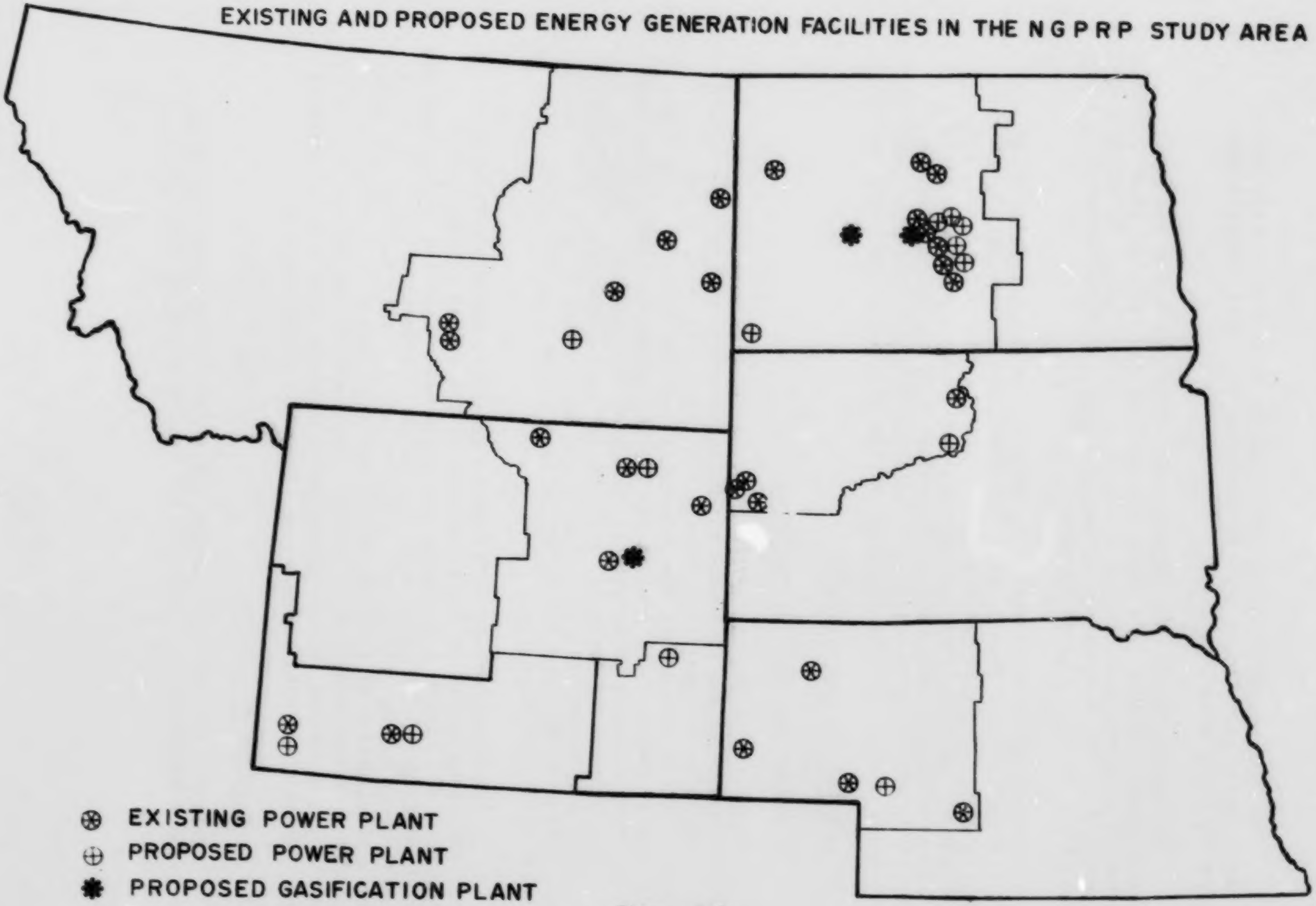

⊛ EXISTING POWER PLANT
⊕ PROPOSED POWER PLANT
✱ PROPOSED GASIFICATION PLANT

Figure I-1a

1.1.2.1 Particulates

A recent EPA report[1] considered the changes in concentrations of total suspended particulates (TSP) and sulfur dioxide (SO_2) at urban and non-urban sites across the United States during the 12-year period 1960-71. Figure I-2, taken from that report, illustrates the time variation of annual geometric mean concentrations of total suspended particulates ($\mu g/m^3$)*for a composite of 95 urban and 18 non-urban sites. On any given year, the range of urban annual averages varied between 30 and 240 $\mu g/m^3$, while the non-urban annual averages ranged between 5 and 85 $\mu g/m^3$. The primary and secondary annual TSP standards are 75 and 60 $\mu g/m^3$, respectively.

Figure I-3[2] indicates that the maximum 24-hour TSP concentrations at these 95 urban stations varied from about 70 to 950 $\mu g/m^3$ in 1968, in comparison to the primary and secondary 24 hour TSP standards of 260 and 150 $\mu g/m^3$m, respectively.

Some interesting trends are noticeable from this data. The composite urban annual TSP mean shows a 20% decrease between the 1960 value of 110 $\mu g/m^3$ and 1971 value of 85 $\mu g/m^3$, both in excess of the primary standard. The composite annual mean for the 18 non-urban stations has remained relatively constant with a value of about 25 $\mu g/m^3$. One also notes that between 1960 and 1971 the composite urban average of maximum daily observations has decreased from about 280 to 200 $\mu g/m^3$.

1.1.2.2 Sulfur Dioxide (SO_2)

The composite annual arithmetic means of SO_2 concentrations at 32 urban National Air Surveillance Network (NASN) stations over an eight-year period is recorded in Figure I-4.[3] The range of annual means varied between 10-200 $\mu g/m^3$ in 1964 and improved to a 5-50 $\mu g/m^3$ range in 1971. Figure I-5[4] illustrates the composite averages of maximum daily values, where one notices that the range of maximum values varied between about 20 and 650 $\mu g/m^3$ in 1964, steadily decreasing to about 10 to 300 $\mu g/m^3$ in 1971.

Both composite averages for annual and maximum daily values show definite downward trends during the eight-year period 1964-71. The annual composite approximately halved in value from 55 to 25 ug/m^3, both less than the primary annual SO_2 standard of 80 $\mu g/m^3$. The composite of maximum daily concentrations also decreased in this period from 180 to 100 $\mu g/m^3$, in comparison to the primary 24 hour SO_2 standard of 365 $\mu g/m^3$.

---

1. "The National Air Monitoring Program: Air Quality and Emissions Trends - Annual Report", U.S. Environmental Protection Agency, Office of Air and Water Programs, Research Triangle Park, N.C. 27711. August 1973, p. 4-8.
2. Air Quality Annual Report, p. 4-9.
3. Ibid, P. 4-15.
4. Ibid, P. 4-15.

* The unit of concentration is ug/m^3, micrograms per cubic meter, where a microgram is one millionth of a gram.

TABLE I-1

NATIONAL AMBIENT AIR QUALITY STANDARDS ($\mu g/m^3$)

Pollutant	Averaging Time	Human Health (Primary) Standards	Public Welfare (Secondary) Standards
Sulfur Oxides (SO_2)	Annual	80	-
	24 hr.	365*	-
	3 hr.	-	1,300*
Particulate Matter	Annual	75	(60)**
	24 hr.	260*	150*
Carbon Monoxide (CO)	8 hr.	10,000*	Same
	1 hr.	40,000*	Same
Oxidants	1 hr.	160*	Same
Hydrocarbons	3 hr.	160*	Same
Nitrogen Oxides	Annual	100	Same

* Not to be exceeded more than once/year.

** Guide to be used in assessing State implementation plans to achieve the 24 hr. standard.

Federal Register
April 30, 1971
September 14, 1973

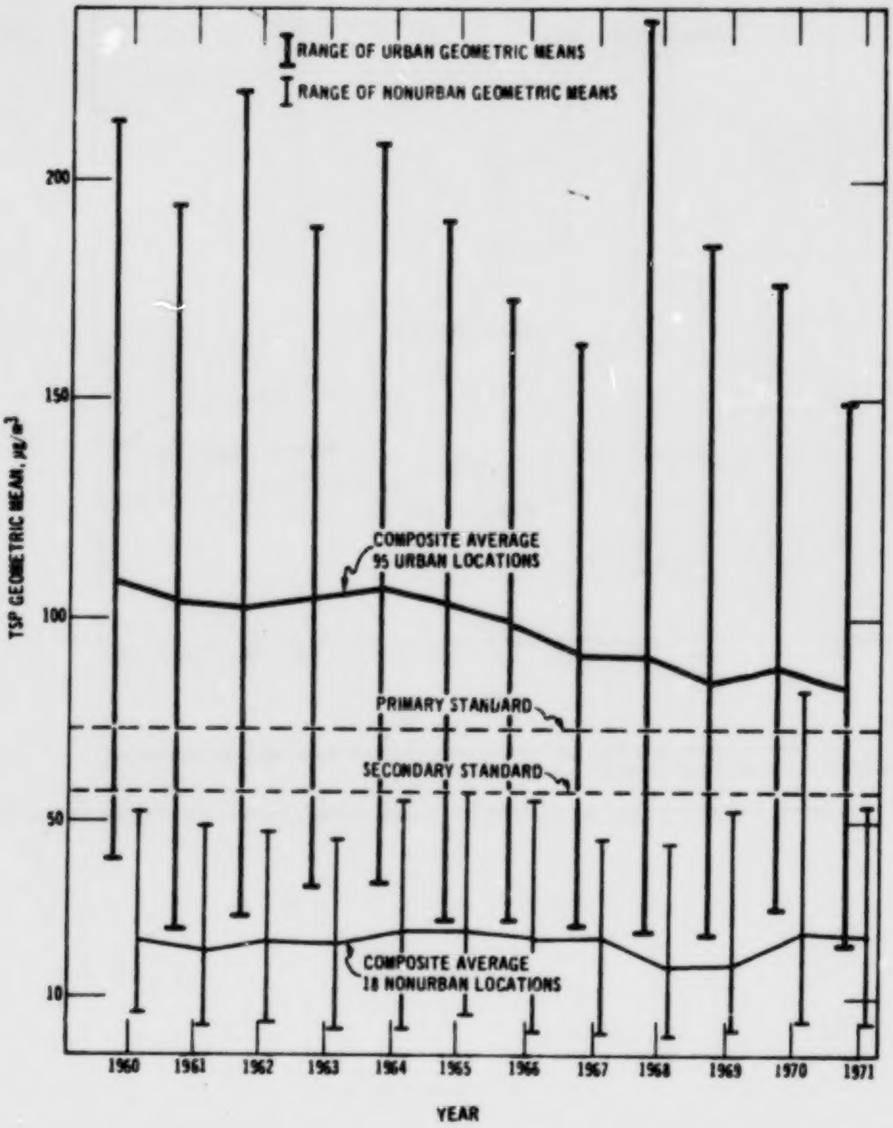


Figure I-2. Composite annual means of total suspended particulate at urban and nonurban NASN stations.

From: "The National Air Monitoring Program: Air Quality and Emission Trends - Annual Report," U.S. EPA Report 450/1-73-001

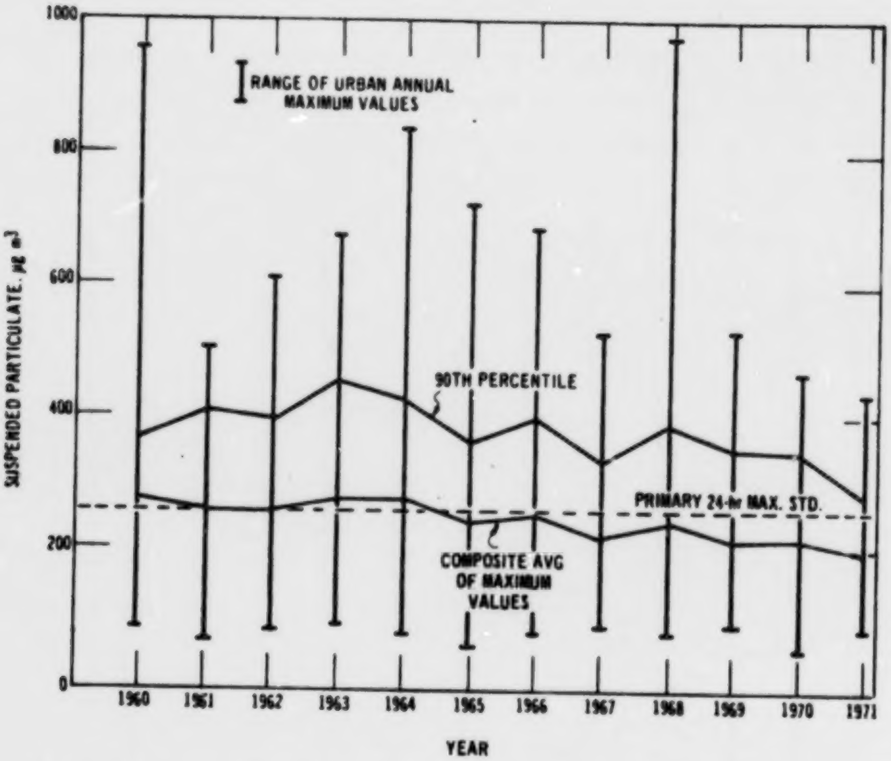


Figure I-3. Composite average and 90th percentiles of annual maximum daily suspended particulate matter concentrations at 95 urban NASN stations.

From: "The National Air Monitoring Program: Air Quality and Emission Trends - Annual Report, U.S. EPA Report 450/1-73-001.

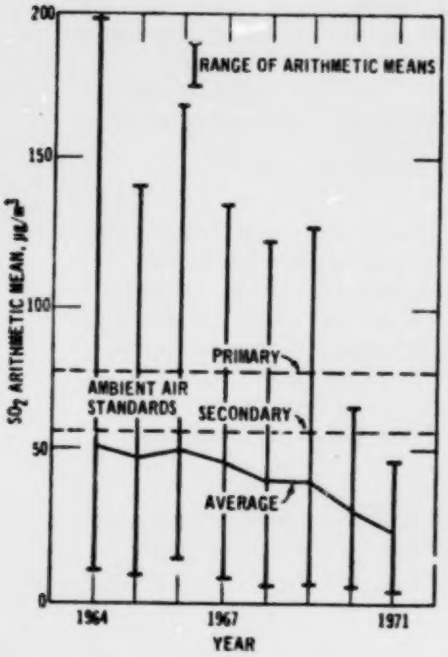


Figure I-4. Composite annual means of sulfur dioxide at 32 NASN stations.

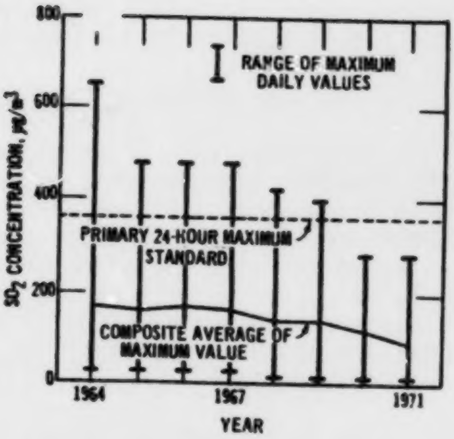


Figure I-5. Composite average of annual maximum daily sulfur dioxide concentrations at 32 urban NASN stations.

1.1.3 NGPRP Air Quality

A total of 33 NASN stations were considered in the five-State NGPRP area. Total suspended particulate concentrations were recorded at every site with high-volume samplers. Several stations in the area also recorded concentrations of other pollutants such as SO_2, NO_x, trace metals (e.g., Beryllium, Manganese, etc.), sulfates and nitrates. Appendix I-A presents this data by site and pollutant, while Appendix I-B contains a description of the pollutant sampling and analyzing methods. This existing air quality data is generally limited to urban centers such as Billings, Bismarck, Casper and Rapid City. The lack of background data in more rural areas makes existing air quality assessment difficult in these regions where large power and gasification plants might ultimately be sited. The NGPRP air quality network described in Section II has been designed to acquire the necessary data.

1.1.3.1 Total Suspended Particulates

Generally, the TSP concentrations in the study area are lower than the national average; this is particularly noticeable when compared with the northeastern and north central United States. Urban annual geometric means in the study area ranged from 42 to 127 $\mu g/m^3$. Of the 33 urban annual means of total suspended particulates listed in Table A-1, for stations with a full year's data, 17 exceeded the annual secondary standard of 60 $\mu g/m^3$ and only four exceeded the primary standard of 75 $\mu g/m^3$. Only two annual values were greater than the national composite annual mean of 85 $\mu g/m^3$,

The higher concentrations were found in the larger urban centers, such as Billings, Bismarck, Casper and Rapid City. Urban stations located in smaller cities (e.g., Minot, Williston) had lower concentrations, generally ranging from 30-50 $\mu g/m^3$.

Annual geometric means for TSP at non-urban stations in the study area were significantly less than urban values, generally in the range of 10-20 $\mu g/m^3$, lower than the above mentioned national non-urban composite average of 25 $\mu g/m^3$. However, a background station 50 miles east of Casper reported a mean of 58 $\mu g/m^3$ for 1973, which could conceivably reflect the presence of the nearby Dave Johnston Plant.

Maximum 24-hour concentrations at urban stations in the study area varied between 57 and 420 $\mu g/m^3$ in 1972, with an average of 211 $\mu g/m^3$, much less than the 1968, but comparable to the 1971 national values (Figure I-3).

Analysis of air quality trends in the study area is difficult since only a few urban and non-urban stations have been recording data for more than three years. The Bismarck and Black Hills stations showed no clear improvement or worsening of air quality over the 1967-72 period. Casper and Minot showed a trend towards higher particulate concentrations during the periods 1967-71 and 1969-72 respectively. TSP concentrations at the non-urban Lake Darling site decreased over the six-year period 1967-72. (See Table A-1 in the Appendix.)

1.1.3.2 Sulfur Dioxide

Measurements of sulfur dioxide concentrations in the study area were conducted at only one urban (Casper, Wyoming) and one non-urban (Black Hills, South Dakota) station. Casper recorded annual SO_2 concentrations as decreasing from 25 to 2 ug/m^3 during the years 1967-72, with the maximum daily concentrations decreasing from 113 ug/m^3 in 1967 to 16 µg/m^3 in 1972. Three years of SO_2 data at the Black Hills station also indicate a downward trend with concentrations decreasing from 8 to 4 µg/m^3 between 1969 and 1972. These values are well below the primary SO_2 standards of 80 ug/m^3 (annual) and 365 ug/m^3 (24 hour), as well as below the national urban and non-urban averages.

1.1.3.3 Nitrogen Oxides (NO_x)

Casper and Black Hills were the only stations reporting NO_x data. Casper's annual arithmetic values ranged between 43 and 68 µg/m^3 during 1968-72, with an average of 53 µg/m^3. The non-urban Black Hills station had annual concentrations varying between 38 and 45 µg/m^3 during 1970-72, with an average of 42 ug/m^3. The primary and secondary annual NO_x standards are both 100 µg/m^3.

1.1.3.4 Trace Metals

Trace metal concentrations have been obtained by analyses of the total suspended particulate filters obtained from high-volume samplers. (Refer to Appendix I-B for details on the analyses). Only three of the stations within the study area -- Bismarck, Casper and Balck Hills -- have recorded trace metals data. Two of these stations are urban; one (Black Hills) is non-urban. The small number of stations and years of data make it difficult to evaluate air quality over the entire study area. However, existing trace metals data for these three sites indicate smaller concentrations than national averages for both urban and non-urban stations.

To provide a comparison reference for the study area concentrations, the averages of the maximum concentration of 12 metals recorded in 149 urban and 28 non-urban stations in the U.S. have been computed and appear in Table I-2. Many stations had all or most of their samples for a year with concentrations below the minimum detectable level. In these cases no statistics were calculated. Table I-3 lists the minimum detectable concentrations for 12 metals.

The maximum concentrations for 12 trace metals in Bismarck and Casper were less than the 1968 national averages as shown in Table I-2. Furthermore, in Casper all samples of 8 of the 12 metals had concentrations below the minimum detectable levels. In Bismarck, all samples for 6 metals had concentrations below the minimum levels.

The Black Hills station had all or most of its samples of 8 metals below the minimum detectable levels in 1968. Table I-2 shows that

TABLE I-2

TRACE METALS

Metal	Average Maximum Observation of 149 Urban Stations (1968) $\mu g/m^3$	Average Maximum Observation of 2 Urban NGPRP Stations (1968) $\mu g/m^3$	Average Maximum Observation of 28 Non-Urban Stations (1968) $\mu g/m^3$	Maximum Observation of 1 Non-Urban NGPRP Station (1968) $\mu g/m^3$
Beryllium	.0005	.0004	.0002	*
Cadmium	.016	*	.002	.007
Chromium	.065	.031	.010	*
Cobalt	.005	*	.001	.002
Copper	.50	.11	0.40	.450
Iron	8.03	4.60	1.07	*
Lead	3.39	1.36	0.20	.024
Manganese	.50	*	.03	*
Nickel	.11	.01	.01	*
Tin	.02	*	.005	*
Titanium	.23	.05	.05	*
Vanadium	.21	*	.02	*

---

* Observations less than minimum dectectable concentrations.

From: Air Quality Data for Metals: 1968 and 1969--From the National Air Surveillance Network, U.S. EPA Publication, June, 1973, APTD 146.9.

TABLE I-3

URBAN AND NON-URBAN DETECTABLE CONCENTRATIONS* FOR METALS, $\mu g/m^3$

Metal	Detectable Concentration	
	Urban	Non-Urban
Beryllium	0.0002	0.00007
Cadmium	0.002	0.0006
Chromium	0.006	0.002
Cobalt	0.004	0.0001
Copper	0.01	0.003
Iron	0.10	0.03
Lead	0.02	0.004
Manganese	0.02	0.01
Nickel	0.005	0.002
Tin	0.001	0.0003
Titanium	0.01	0.003
Vanadium	0.003	0.001

*Non-urban emission spectrographic measurements (Appendix B) show less interference, and consequently have smaller minimum detectable concentrations than urban samples.

concentrations of Cadmium, Cobalt, and Copper at Black Hills exceeded the national non-urban averages.

In conclusion, air quality data for the rural NGPRP study area is severely lacking. Existing NGPRP data for particulate matter, SO_2, NO_x and trace metals indicate a higher air quality than national averages.

1.2 TOPOGRAPHY

The topography of the study area is significant in that it influences the dispersal of pollutants and helps explain climatic patterns such as temperature and precipitation. Figure I-6 is a map of the NGPRP study area of eastern Montana, northeastern Wyoming, western North Dakota and northwestern South Dakota, developed by the NGPRP Regional Geology Work Group.* Based on the work of Edwin Hammond,[5, 6] the map shows broadscale land form classes based on two terrain characteristics -- slope and local topographic relief. Each land form class is described by a letter (A, B, C or D) and a number (1, 2, 3, 4, 5 or 6). Letters symbolize the approximate slope characteristics of the land area -- "A" designating more than 80% of area gently sloping (less than 8% slope), "B" with 50% - 80%, "C" with 20% - 50%, and finally, "D" designating less than 20% slope of area as gently sloping. Numbers indicate local relief ranging from 0 to 100 feet ("1") to over 3000 feet ("6").

Figure I-6 indicates a gradual change of slope and terrain between the various land form categories. As a result, we can expect that terrain of the NGPRP study area will not be as important a factor in pollutant dispersal as it is in, for example, the Four Corners area of Arizona, Colorado, New Mexico and Utah. Furthermore, we expect that precipitation and temperature variation across the study area will be small.

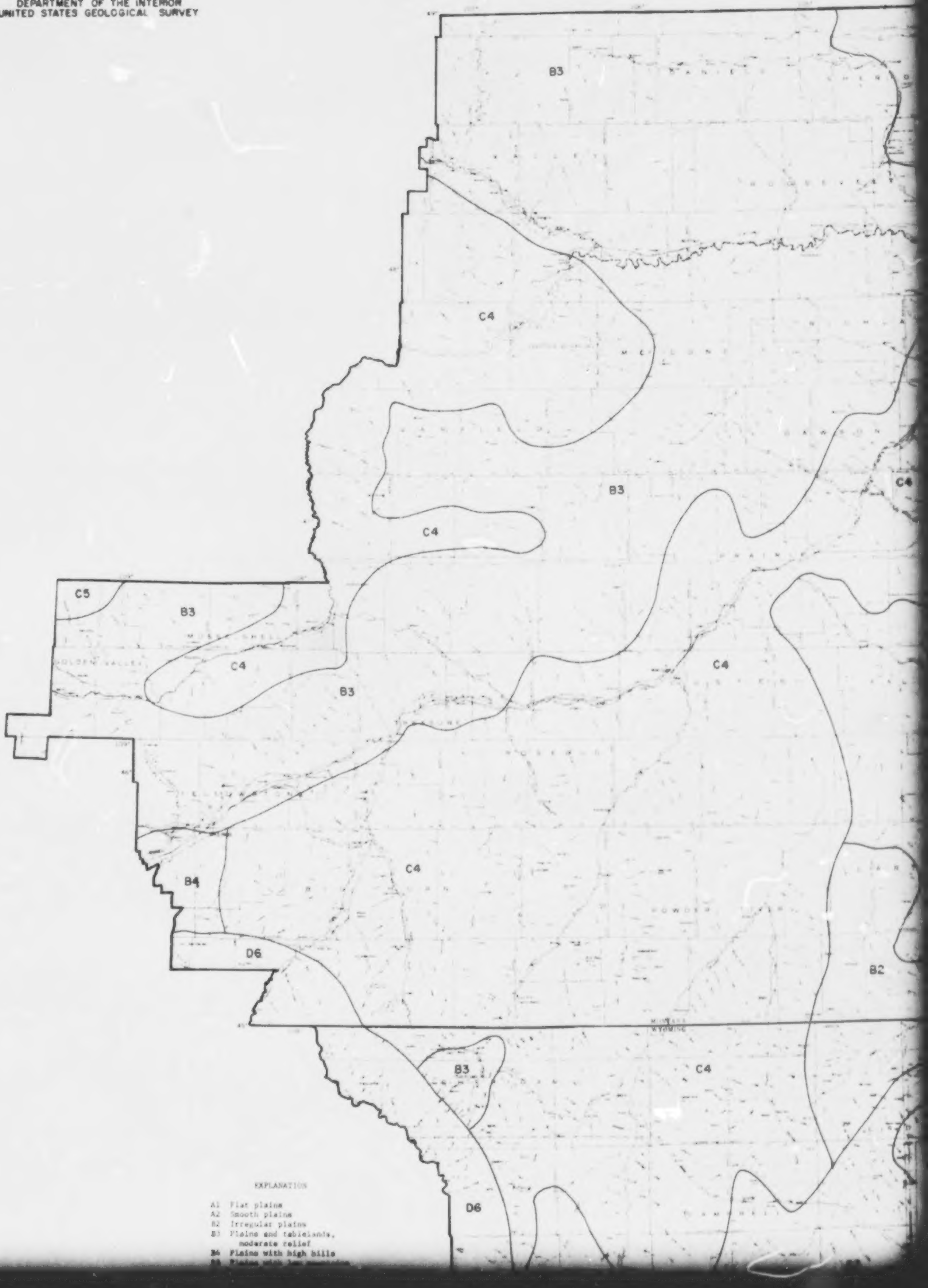
---

5. E. H. Hammond. "Analysis of Properties in Land Form Geography; An Application to Broadscale Land From Mapping." Annals Assoc. Amer. Geographers. pp. 11-19. 1964.

6. Classes of Land Surface Form in the U.S., U.S.G.S. National Atlas of the United States. pp. 61-64.

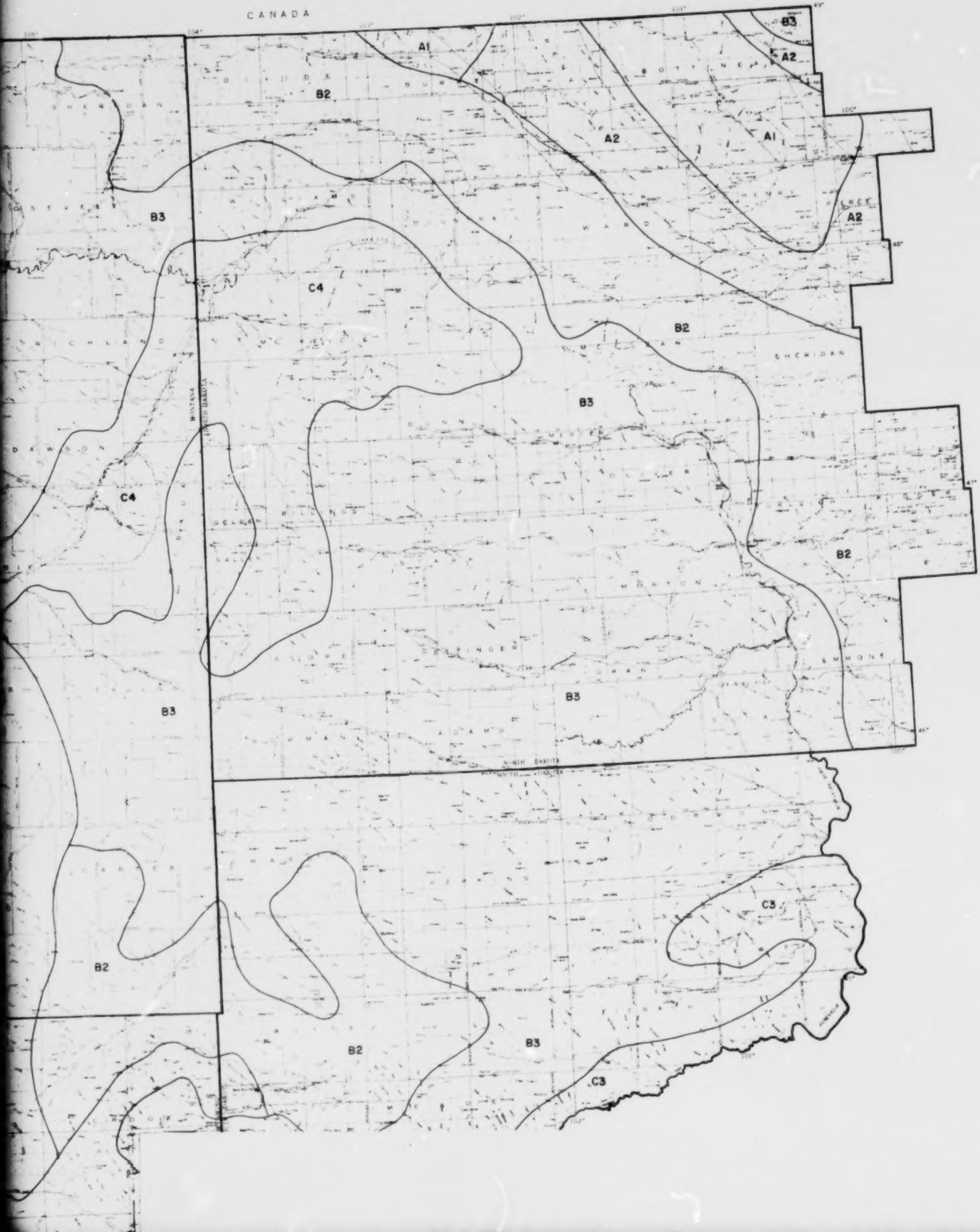
* Southwestern Wyoming and Nebraska were not originally under consideration by the Regional Geology Work Group at the time the map was made.

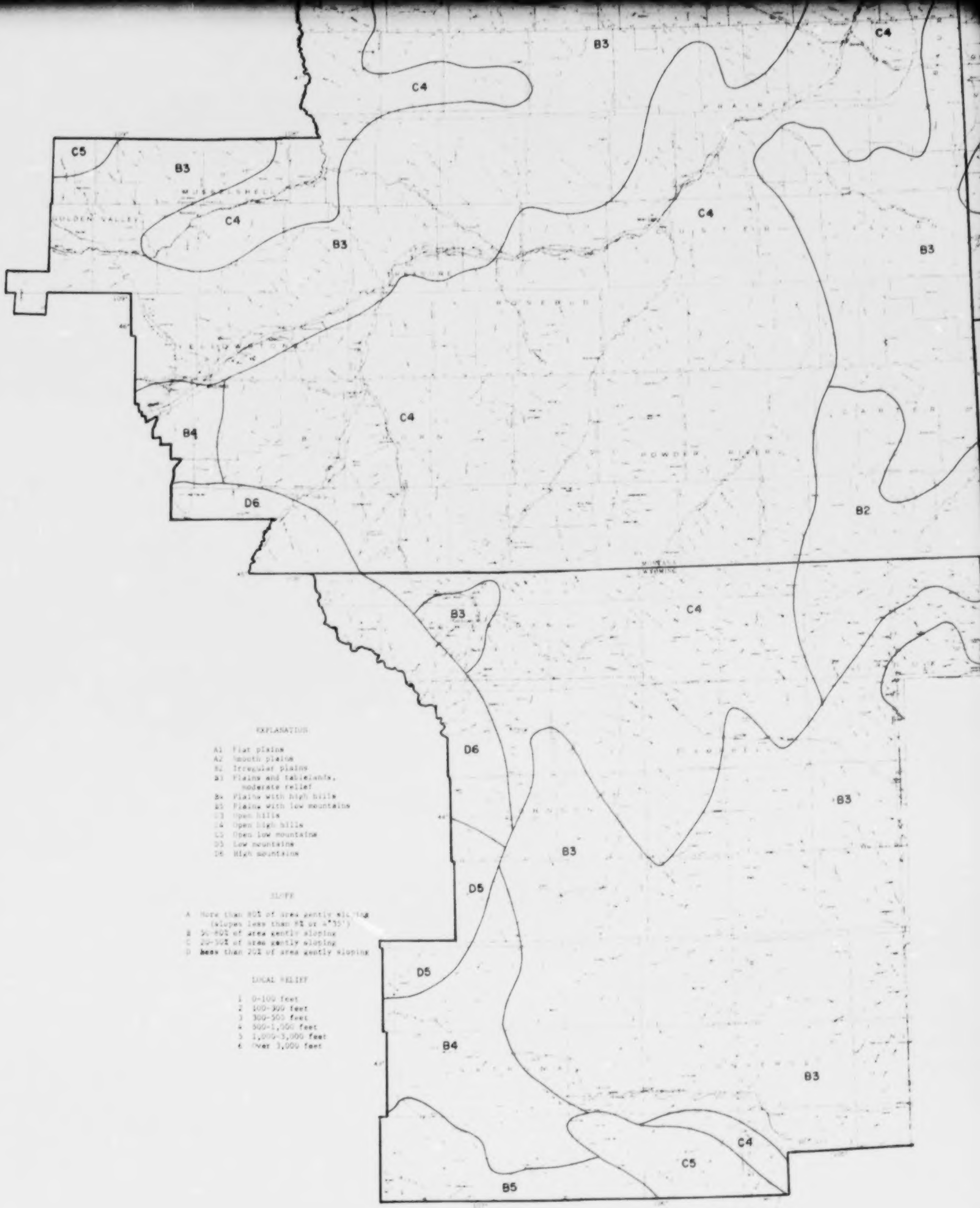
DEPARTMENT OF THE INTERIOR
UNITED STATES GEOLOGICAL SURVEY


B3
C4
B3
C4
C4
C5
B3
MUSSELSHELL
GOLDEN VALLEY
C4
B3
C4
C4
B4
D6
B2
MONTANA
WYOMING
B3
C4
D6

EXPLANATION

A1 Flat plains
A2 Smooth plains
B2 Irregular plains
B3 Plains and tablelands,
moderate relief
B4 Plains with high hills
B5 Plains with low mountains


CANADA
105°
104°
103°
102°
101°
100°
49°
48°
47°
46°
A1
A2
B2
B3
C3
C4
DIVIDE
BURKE
BOTTINEAU
SHERIDAN
WILLIAMS
MOUNTRAIL
WARD
MCHENRY
PIERCE
ROOSEVELT
RICHLAND
MCKENZIE
MCLEAN
DAWSON
DUNN
OLIVER
BILLINGS
GOLDEN VALLEY
STARK
MORTON
EMMONS
SLOPE
HETTINGER
GRANT
BOWMAN
ADAMS
CARTER
PERKINS
CORSON
MONTANA
NORTH DAKOTA
SOUTH DAKOTA


B3
C4
C4
C5
B3
MUSSELSHELL
GOLDEN VALLEY
C4
B3
C4
B3
B4
C4
D6
B2
B3
C4
D6
B3
B3
D5
D5
B4
B3
C4
C5
B5

EXPLANATION

A1 Flat plains
A2 Smooth plains
B2 Irregular plains
B3 Plains and tablelands, moderate relief
B4 Plains with high hills
B5 Plains with low mountains
C3 Open hills
C4 Open high hills
C5 Open low mountains
D5 Low mountains
D6 High mountains

SLOPE

A More than 80% of area gently sloping (slopes less than 8% or 4°35')
B 50-80% of area gently sloping
C 20-50% of area gently sloping
D Less than 20% of area gently sloping

LOCAL RELIEF

1 0-100 feet
2 100-300 feet
3 300-500 feet
4 500-1,000 feet
5 1,000-3,000 feet
6 Over 3,000 feet

Base from U.S. Geological Survey
State base maps

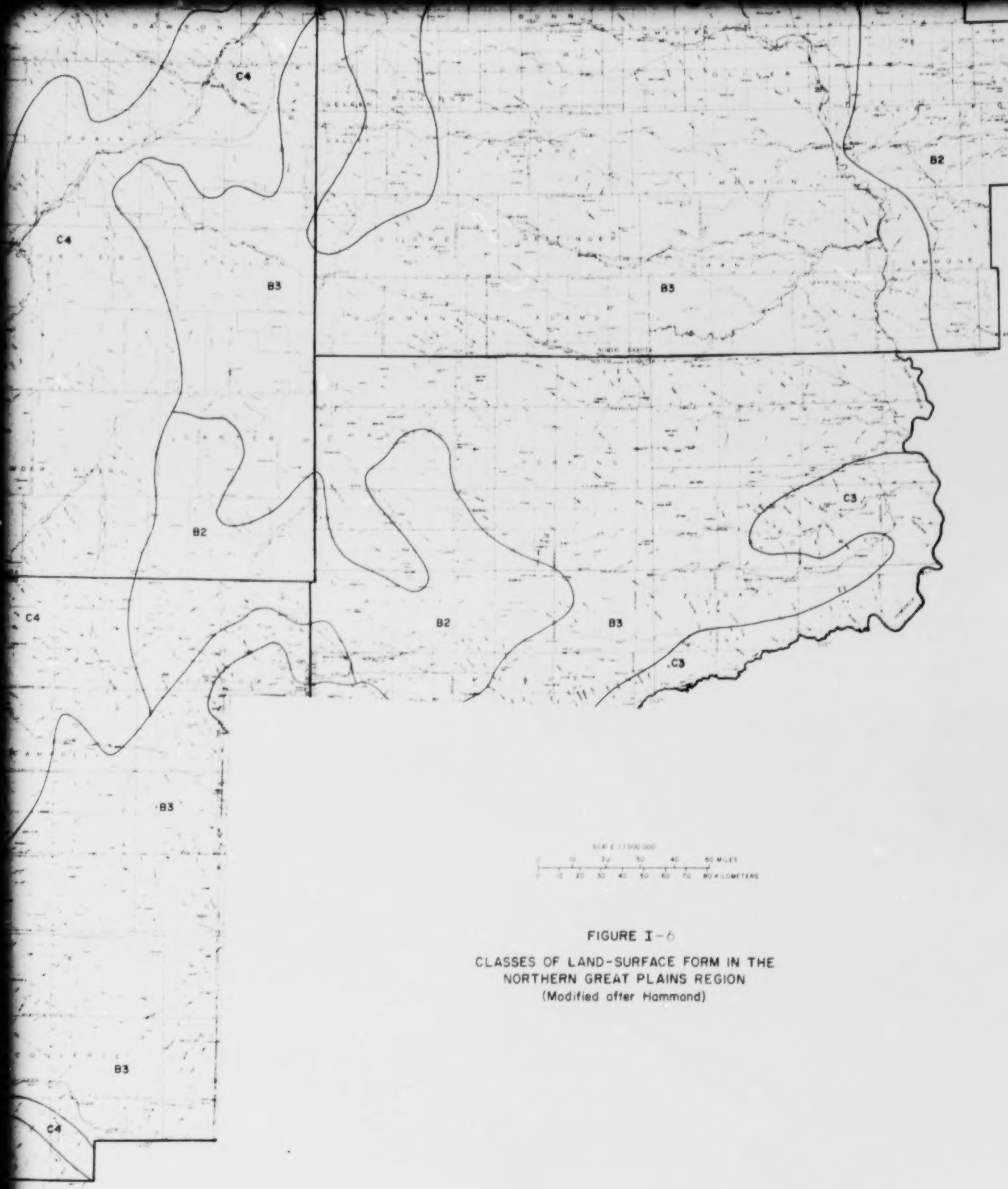

DAWSON
C4
C4
B3
B2
B2
B3
B2
B3
C3
C3
C4
B3
B3
C4
GOLDEN VALLEY
MORTON
SLOPE
HETTINGER
GRANT
BOWMAN
ADAMS
EMMONS
NORTH DAKOTA
SOUTH DAKOTA
CARTER
POWDER RIVER
CAMPBELL
CONVERSE
0 10 20 30 40 50 MILES
0 10 20 30 40 50 60 70 80 KILOMETERS

FIGURE I-6

CLASSES OF LAND-SURFACE FORM IN THE NORTHERN GREAT PLAINS REGION
(Modified after Hammond)

1.3. CLIMATOLOGY OF THE STUDY AREA

1.3.1. Overview

The climates of the states included in the Northern Great Plains study area may be described in general as typical, mid-latitude, continental climate. The Rocky Mountains, which are located west of the study area, have a pronounced influence on the types of air masses, and atmospheric flow patterns, which create the climate characteristics of the area. The Rocky Mountains act as a barrier to the moist Pacific air in the prevailing westerly flow. Because of orographic effects, temperature and moisture in the air masses originating in the Pacific undergo major modification by the time they reach the Northern Great Plains. This influence is less pronounced in the western part of the study area over Wyoming and Montana where Pacific air masses frequently exist.

There are no major terrain barriers which modify air masses originating in the cold polar regions of Canada, or the warm moist regions of the Gulf of Mexico as they overflow the study area. Therefore, air masses from these regions frequently cover the area with only minor modification of their original characteristic. The gradual changes in topography do not cause major spatial variations in climatic conditions.

Frequent weather changes occur over the area with the passage of cold fronts and their associated pressure systems, which generally follow an easterly track. The oscillating but generally, prevailing westerly winds at higher altitudes steer the lower level air mass movements. The pronounced Cold Polar and Arctic outbreaks which overflow the area during colder times of the year are associated with large amplitude wind patterns in the prevailing westerly windflow having strong northerly steering winds aloft over the western portion of the area. The invasion of warm moist Gulf air over the region is usually accompanied by southwesterly steering winds aloft.

Because of the frequent weather changes which result from rapid movement of storm systems through the area, stagnant air masses, which cause poor atmospheric dispersion conditions, occur rather infrequently. Warm windy periods during the winter may occur as a result of warm winds reaching 25 to 50 miles per hour. These warm winds may last for several days and will tend to aid in the dispersion of any atmospheric pollutants. These winds, commonly called "chinooks", occur predominantly near the Eastern side mountain ranges in Wyoming, Montana, and the Black Hills in South Dakota.

Surface wind data were obtained from several stations located on the fringe of the study area. Annual average wind speeds ranged from 8 to 13 mph, with Casper, Wyoming recording the highest. Annual wind roses, for stations in each of the five states, are presented in section 1.3.2.

The annual average temperature varies between 42^{o} and $49^{o}F$, with annual average highs of $50-60^{o}F$ and average lows of $30-35^{o}F$. Nebraska generally records the highest surface temperature.

The annual mean relative humidity for the study area is 60%. The average for the fall and winter quarters is about 70%. This may be important in any attempts to discuss pollutant reaction times. SO_2, for example, is believed to have a reaction time which is a function of relative humidity.

Annual precipitation in the region varies from 10 to 20 inches per year. Montana and Wyoming, 10 to 16 inches, are more arid than the three eastern states. Generally, 50% of the rainfall occurs during the summer season, and winter is the driest time of year.

Eastern Montana, Nebraska and the Dakotas receive approximately 36 inches of snow annually, with the exception of the Black Hills area, which receives 60 to 100 inches per year. Wyoming receives 36 to 60 inches in the northeast, 60 to 100 inches in the southwest, and 100 to 200 inches in the Big Horn Mountains.

The Northern Great Plains receives between 60 and 70 percent of total possible sunshine annually. This factor could be significant since hydrocarbons and nitrogen oxides would be present in the atmosphere if coal gasification plants are constructed. Sunshine is needed to initiate atmospheric photochemical reactions.

The dispersive ability of a plume is dependent upon the volume of air available for mixing. The so-called mixing layer height, which is defined as the thickness of the layer above the earth's surface within which vertical mixing is enhanced, indicates the volume of air available for mixing, with small values implying a greater potential for high air pollution concentrations. Mixing heights are calculated using surface temperature and temperatures at various altitudes. A summary of the mixing heights for the Northern Great Plains is presented in this section. One notes that the worst conditions occur in the morning and during the winter months.

The mixing depth numbers presented here will be augmented with information now being obtained from atmospheric aspects meteorological data collection contracts (see section II).

The occurrence of poor dispersion situations for the Northern Great Plains may be indicated using Holzworth's (1972) work. Considering mixing heights of 500, 1000, 1500 and 2000 meters and wind speeds of 2, 4 and 6 meters per second, he investigated the probable occurrence of periods of restricted dispersion of two and five day durations. His findings, using wind speeds equal to or less than 6 meters per second, are summarized in section 1.3.5. The most unfavorable dispersion conditions normally occur during the winter months. Supplementary data will be obtained using pilot balloons and temperature sondes to determine the frequency of temperature inversions and other parameters related to poor dispersion for the specific study area.

1.3.2. Wind

Wind is instrumental in the diffusion of pollutants released into the atmosphere. Wind is air in motion relative to the earth's surface, and this motion can be in any direction, horizontal or vertical. Because the vertical portion of the motion is usually much less than the horizontal component, it is generally the horizontal winds that are measured and recorded.

1.3.2.1. Surface Winds

Annual and seasonal mean wind speeds at 13 National Weather Service Stations are tabulated in Table I-4. January, April, July and October were chosen as months representative of each of the four seasons.

Annual mean wind speeds varied between 7.0 mph and 13.0 mph. Casper and Rock Springs, Wyoming had the highest averages (13.0 mph and 12.3 mph respectively), while Lander, Wyoming showed the lowest (7.0 mph).

Casper has an average January (Winter) mean speed of 16.8 mph, the highest of all the 13 stations. Generally, the maximum mean seasonal speeds occurred in Spring, while the minimum seasonal wind speeds occurred in Winter or Summer.

Prevailing wind directions, i.e., the most frequently observed wind directions, are also given in Table I-4 for the 13 stations and the five time periods. The four Wyoming stations show less variation throughout the year in prevailing wind direction than the stations of the remaining four states.

To give some indication of wind speed extremes, Table I-5 is included, which lists the fastest mile of wind and the accompanying wind direction observed at 10 study area stations. The fastest mile of wind is the fastest wind speed in miles per hour of any "mile" of air. Thus, the fastest mile is not an instantaneous value of wind speed, but rather a wind which persists long enough for one mile of air to flow past the wind speed sensor in the least amount of time.

The largest values of the fastest mile were recorded at Sheridan, Wyoming (84 mph) and Scottsbluff, Nebraska (80 mph), while the lowest was observed at Glasgow, Montana (44 mph). Six of the ten fastest miles occurred in Summer. Wind directions associated with the fastest mile were generally westerly (NW-W-SW directions), with the exception of Lander, which recorded S-SW wind directions.

The distribution of observed wind directions is graphically illustrated in the wind rose, which indicates the percentage of time

TABLE I-4

PREVAILING DIRECTION, MEAN SPEED (MPH) AT SELECTED STATIONS

	ANNUAL		JANUARY		APRIL		JULY		OCTOBER	
	Prevailing[1] Wind Direction	Mean Speed	Prevailing Wind Direction	Mean Speed	Prevailing Wind Direction	Mean Speed	Prevailing Wind Direction	Mean Speed	Prevailing Wind Direction	Mean Speed
MONTANA										
Billings	SW	11.3	SW	12.9	SW	11.8	SW	9.8	SW	11.2
Glasgow	-	11.1	-	11.2	-	14.1	-	10.2	-	11.2
Miles City	SE	9.9	NW	9.2	NW	11.6	SE	9.4	SSE	9.6
NEBRASKA										
North Platte	NW	10.5	NW	9.5	N	12.9	SE	9.7	SSE	9.7
Scottsbluff	ESE	10.9	WNW	10.9	NW	13.0	ESE	9.4	NW	10.0
Valentine	S	10.9	W	10.1	N	12.5	S	10.1	S	10.4
NORTH DAKOTA										
Bismarck	WNW	10.8	WNW	10.2	WNW	12.8	SSE	9.8	WNW	10.4
Williston	SE	7.6	W	6.8	SE	8.8	SE	7.0	SE	7.5
SOUTH DAKOTA										
Rapid City	NNW	11.0	NW	10.0	NNW	13.0	NNW	10.0	NNW	11.0
WYOMING										
Casper	SW	13.0	SW	16.8	WSW	12.9	WSW	9.9	SW	12.4
Lander	SW	7.0	SW	6.3	SW	8.0	SW	7.6	SW	6.2
Rock Springs	W	12.3	W	13.6	W	13.0	W	10.1	W	11.0
Sheridan	NW	8.0	NW	7.7	NW	9.9	NW	7.2	NW	7.5

---

1. Prevailing means most frequently observed.

TABLE I-5

FASTEST MILE OF WIND AND ACCOMPANYING WIND DIRECTION

	ANNUAL	WINTER	SPRING	SUMMER	FALL
MONTANA					
Billings	79 NW[1]	72 W	72 NW	79 NW	68 NW
Glasgow	44 300°[2]	40 320°	44 300°	41 330°	44 320°
NEBRASKA					
North Platte	72 SW	68 N	70 S	60 NW	72 SW
Scottsbluff	80 WNW	60 WNW	80 NW	80 WNW	45 WNW
Valentine	65 NW	45 N	50 NW	65 NW	50 NW
NORTH DAKOTA					
Bismarck	72 W	61 NW	65 NW	72 W	65 NW
Williston	60 W	47 NW	45 W	60 W	53 NW
SOUTH DAKOTA					
Rapid City	65 W	61 NW	65 W	65 NW	52 NW
WYOMING					
Lander	77 SW	77 SW	72 SW	58 S	70 SW
Sheridan	84 SW	73 NW	71 NW	73 W	84 SW

---

1. To 8 compass points only.
2. Direction expressed in degrees from true north.

the wind blew from sixteen compass points or was calm. Annual wind roses for eight study area stations are displayed in Figure I-7. Seasonal roses appear in the Appendix in Figures A-1 (Winter); A-2 (Spring); A-3 (Summer); and A-4 (Fall).

The Casper wind roses exhibit a large predominance of winds from the southwest, especially in Fall and Winter (35%, and 40% of the time respectively). Considering winds from the WSW and SW, these percentages for Casper become 45% and 60% respectively.

1.3.2.2. Upper Winds

Results of upper wind observations in the Northern Western Hemisphere were reported by Crutcher and Halligan (1967). Charts displaying lines of equal mean wind speed, and mean wind direction, were constructed for six altitide levels (850 mb, 700 mb, 500 mb, 300 mb, 200 mb and 100 mb) and for each season. Figures I-8 and I-9 are isoline diagrams for winter wind speed and direction at the 500 mb altitude level. Values of wind speed and direction representative of the four seasons in the NGPRP study area are presented in Table I-6 for two altitude levels, 700 mb and 500 mb.* The altitudes corresponding to these constant pressure levels vary as a function of atmospheric conditions (e.g., density, temperature). However, the relation between pressure and altitude can be used from the "standard atmosphere", which is a model vertical distribution of pressure, temperature and density which is assumed representative of the atmosphere. This hypothetical dependence of pressure, temperature and density on altitude is derived assuming that the air obeys the ideal gas law and the hydrostatic equation; the air contains no water vapor; and the acceleration of gravity does not vary with height. The approximate altitudes corresponding to pressure levels of 700 mb and 500 mb, in the "standard atmosphere", are 10,000 ft MSL (3000 m) and 18,000 ft MSL (5500 m) respectively.

Wind directions at these altitudes are generally westerly, varying between 240° and 300° (clockwise from North). Winter and Fall winds blow from the northwest, while Spring winds are observed to blow from the west, and Summer winds from the southwest.

Mean wind speeds generally increase with altitude through the depth of the atmosphere of concern here (850-500 mb).

Additional information on upper winds is contained in section 1.3.4, which contains a discussion of mixing layer heights in the study area.

1.3.3. Surface Air Temperatures

1.3.3.1. Annual Temperatures

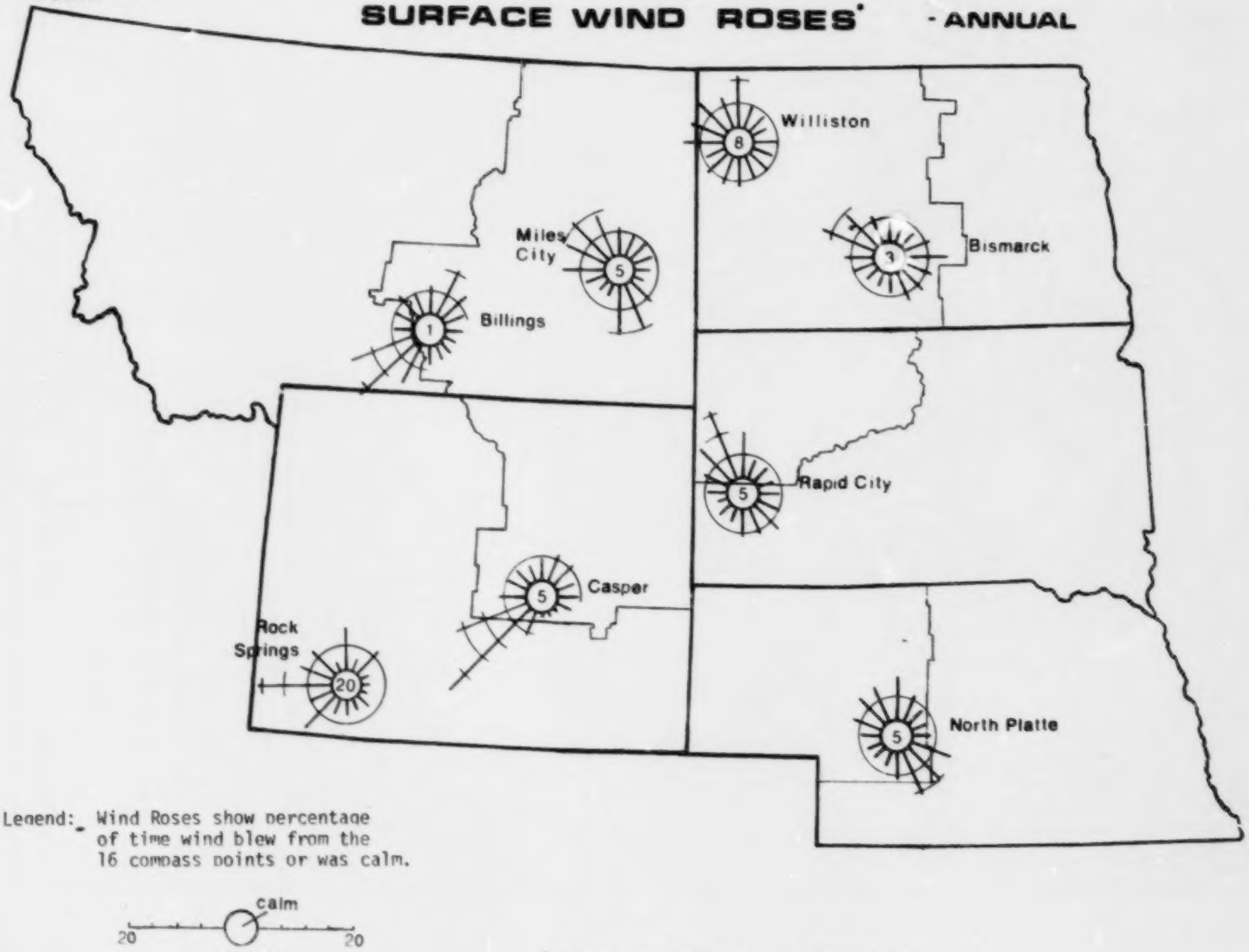
Considerable variation in temperature occurs between the Summer and Winter seasons in the study area. Record highs exceed 100°F, while

---

* 1 mb represents the millibar, a unit of pressure. One millibar = .02953 inches of Hg (32°F) = .01450 psi = 1000 dynes/cm^2.

FIGURE I-7.

SURFACE WIND ROSES* - ANNUAL


Williston
8
Miles City
5
Bismarck
3
Billings
1
Rapid City
5
Casper
5
Rock Springs
20
North Platte
5
calm
20
20

Legend: Wind Roses show percentage of time wind blew from the 16 compass points or was calm.

* from: National Weather Service Data

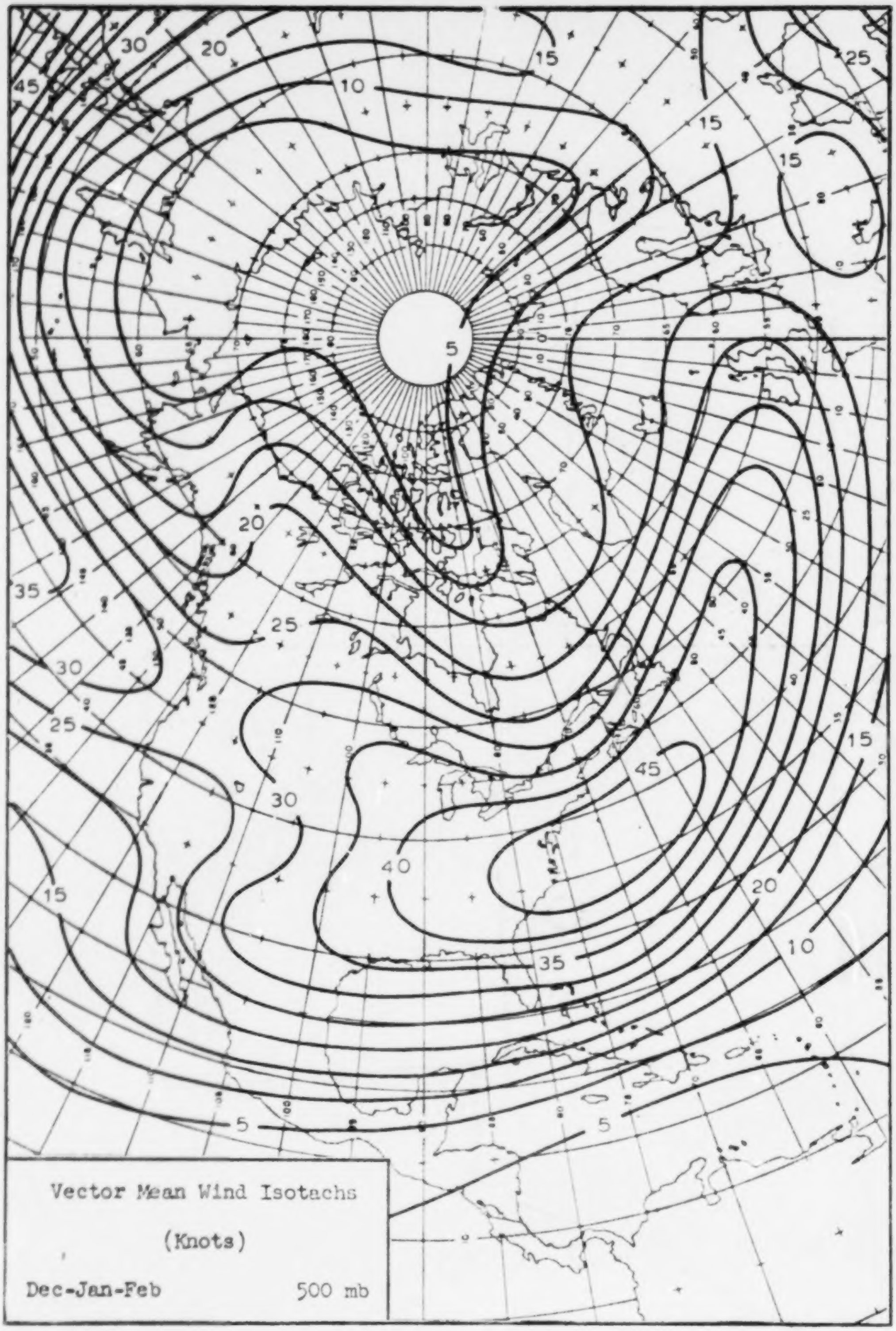

30
20
15
25
45
10
15
15
5
20
35
25
30
25
30
45
15
40
20
15
35
10
5
5
Vector Mean Wind Isotachs
(Knots)
Dec-Jan-Feb
500 mb

FIGURE I-8. VECTOR MEAN WIND SPEED ISOTACHS (KNOTS)
WINTER SEASON. 500 MB LEVEL.
(FROM CRUTCHER AND HALLIGAN (1967))

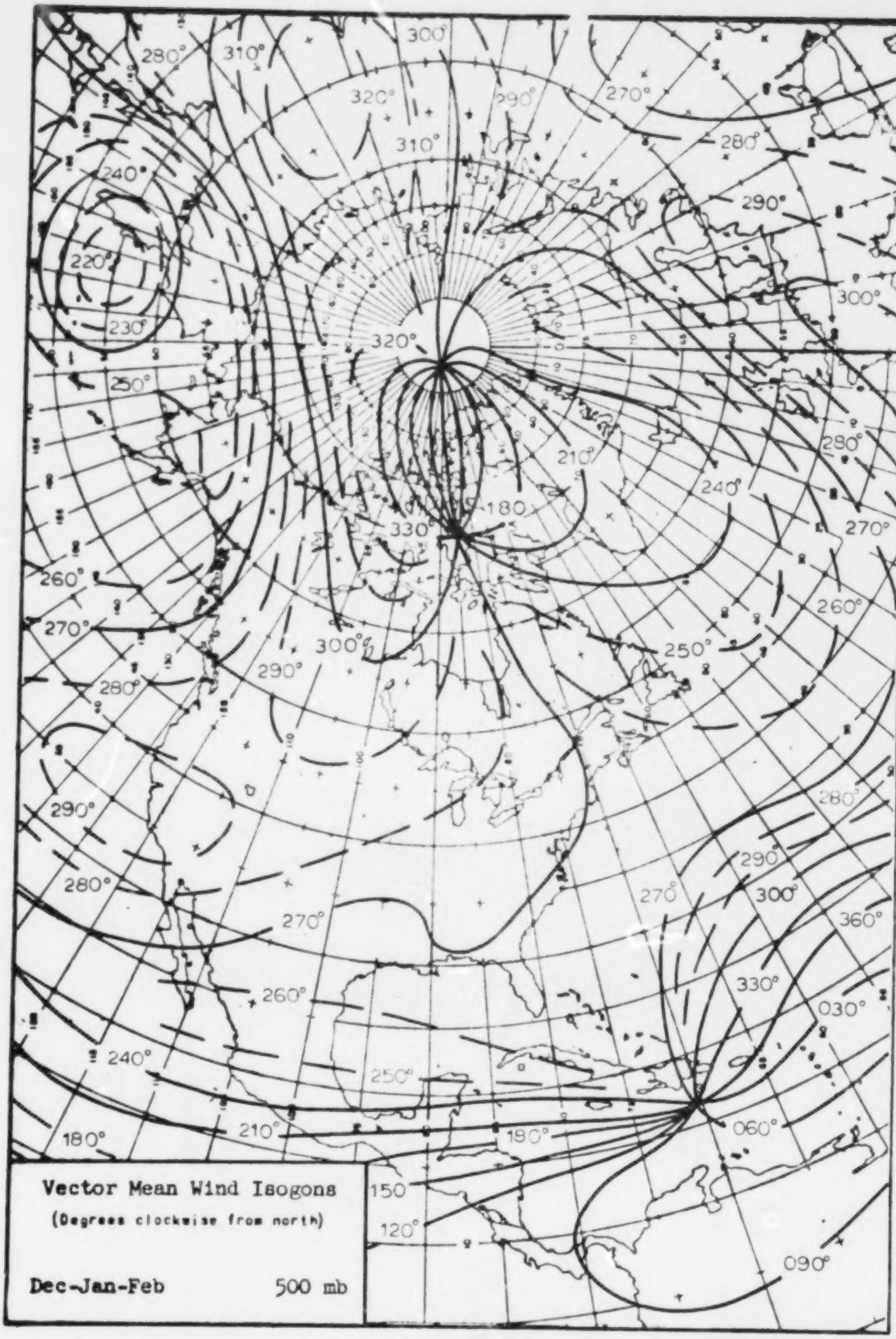

Vector Mean Wind Isogons
(Degrees clockwise from north)
Dec-Jan-Feb
500 mb
280°
310°
300
320°
290°
270°
310°
280°
240°
290°
220°
300°
230°
320°
250°
280°
210°
240°
180
330°
270°
260°
260°
270°
300°
250°
290°
280°
290°
280°
290°
300°
280°
270°
270°
360°
260°
330°
030°
240°
250°
210°
180°
180°
060°
150
120°
090°

FIGURE I-9. VECTOR MEAN WIND DIRECTION ISOGONS (DEGREES CLOCKWISE FROM NORTH) WINTER SEASON. 500 MB LEVEL. (FROM CRUTCHER AND HALLIGAN (1967))

TABLE I-6. **Mean Wind Speed and Wind Direction at Selected Altitudes for NGPRP Study Area[1]**

Altitude[2] Level	Winter		Spring		Summer		Fall	
	Mean Wind Speed (Knots)[3]	Wind Direction[4]	Mean Wind Speed (Knots)	Wind Direction	Mean Wind Speed (Knots)	Wind Direction	Mean Wind Speed (Knots)	Wind Direction
700 mb (3,000 m MSL) (10,000 ft MSL)	20	280°-300°	10	270°-290°	10	260°-280°	15	280°-290°
500 mb (5,500 m MSL) (18,000 ft MSL)	30	280°-290°	20-25	280°	20-25	260°-270°	25	285°

1. From Crutcher and Halligan (1967)
2. Altitudes derived from the Standard Atmosphere
3. 1 knot = 1 nautical mile/hour = 0.5144 meter/sec
4. Measured clockwise from north

record lows are below -30°F, as documented in Figure I-10, which displays annual temperature averages, normals and extremes. The seven stations represented in this figure exhibit small spatial variations. However, over relatively flat terrain, higher temperatures are found generally at more southern latitudes (e.g., Nebraska, in the case of the NGPRP area). The loci of points of equal temperatures, or isotherms, generally parallel lines of latitude in this case. Mountainous areas (e.g., the Black Hills, and the Big Horn Mountains) are exceptions. Normal annual averages ranged from 42° to 49°F; normal lows varied between 29° and 35°F; while normal highs varied between 53° and 63°F.

Table I-7 lists the occurrences of the following selected temperature events during a normal year and normal seasons at 13 stations:

1. The number of days the maximum daily temperature was 90°F or above.

2. The number of days the maximum daily temperature was 32°F or below.

3. The number of days the minimum daily temperature was 32°F or below, and

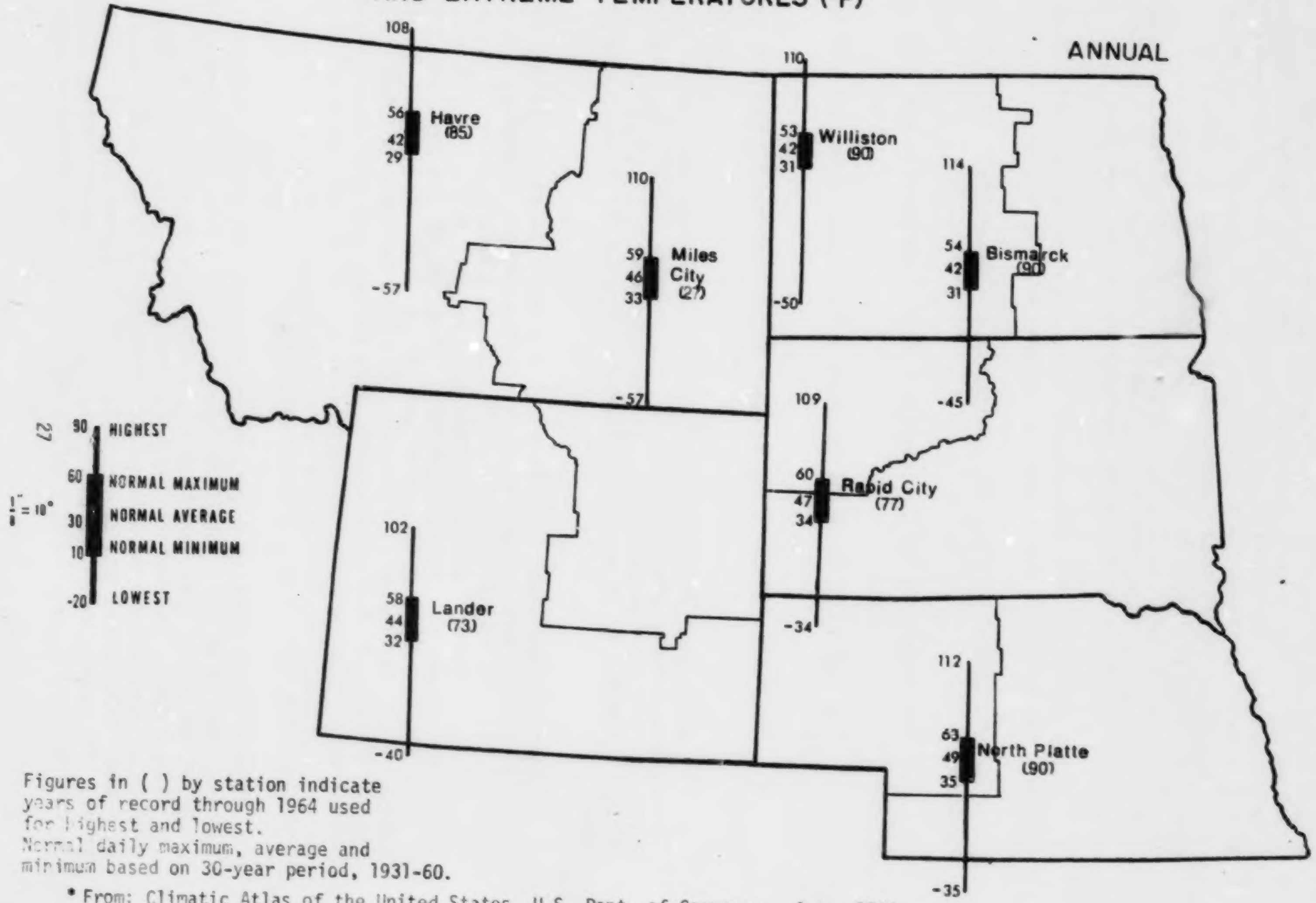
4. The number of days the minimum daily temperature was 0°F or below.

The study area experiences between 20 to 40 days per year where the maximum temperatures exceed 90°F, and between 150-180 days per year where the minimum temperatures are less than 32°F. Stations at higher latitudes or in mountainous areas recorded the lower temperatures.

Another temperature related statistic which is of use is the heating degree day. Heating degree days are the number of degrees the daily average temperature is less than 65°F. Since space heating is normally not required when the outside temperature exceeds 65°F, heating degree days are a measure of fuel consumption. Heating degree days are cumulative. That is, the sum of degree days for a given time period (month, season, year, for example) represents the heating load for that period. There is also a linear relationship between fuel consumption and heating degree days. For example, if one season has twice the number of degree days as another, the fuel consumption attributable to heating will average twice that of the latter season.

Normal total heating degree days (seasonal and annual) are tabulated for stations in or near the NGPRP study area in Table I-8. More northern areas of the study area have a greater number of degree days (e.g., Williston, 9243) than warmer southern sites (e.g., Scottsbluff, 6673). Generally, the study area accumulates between 6,000 and 9,000 degree days over the plains, and approximately 10,000 degree days in mountainous areas. By comparison, central Florida and the Colorado Rockies accumulate approximately 500 and 11,000 heating degree days, respectively, each year.

FIGURE I-10. NORMAL DAILY MAXIMUM, AVERAGE, MINIMUM AND EXTREME TEMPERATURES (°F) *


ANNUAL
108
56
42
29
Havre
(85)
-57
110
59
46
33
Miles City
(27)
-57
110
53
42
31
Williston
(90)
-50
114
54
42
31
Bismarck
(90)
-45
109
60
47
34
Rapid City
(77)
-34
102
58
44
32
Lander
(73)
-40
112
63
49
35
North Platte
(90)
-35
1/8" = 10°
90 HIGHEST
60 NORMAL MAXIMUM
30 NORMAL AVERAGE
10 NORMAL MINIMUM
-20 LOWEST

Figures in ( ) by station indicate years of record through 1964 used for highest and lowest.
Normal daily maximum, average and minimum based on 30-year period, 1931-60.

* From: Climatic Atlas of the United States, U.S. Dept. of Commerce. June, 1968.

TABLE I-7

OCCURRENCE OF SELECTED TEMPERATURE EVENTS

	ANNUAL				WINTER				SPRING				SUMMER				FALL			
	# of Days[1] Temperatures				# of Days Temperatures				# of Days Temperatures				# of Days Temperatures				# of Days Temperatures			
	MAX		MIN		MAX		MIN		MAX		MIN		MAX		MIN		MAX		MIN	
	90°	32°	32°	0°	90°	32°	32°	0°	90°	32°	32°	0°	90°	32°	32°	0°	90°	32°	32°	0°
MONTANA																				
Billings	29	46	150	18	0	33	80	15	0	8	40	2	27	0	0	0	2	5	30	1
Glasgow	24	88	185	49	0	66	100	41	0	14	52	6	22	0	0	0	2	8	44	2
Miles City	23	51	192	10	0	43	87	10	0	4	55	1	23	0	0	0	1	5	49	0
NEBRASKA																				
North Platte	30	42	181	17	0	33	90	17	2	6	45	1	25	0	0	0	3	3	45	0
Scottsbluff	34	31	172	15	0	23	86	13	2	5	42	1	30	0	0	0	3	4	43	0
Valentine	39	51	177	26	0	39	90	23	2	9	45	2	32	0	0	0	5	4	42	1
NORTH DAKOTA																				
Bismarck	22	86	186	50	0	61	90	42	1	15	52	6	18	0	0	0	3	10	44	3
Williston	18	86	180	43	0	61	90	37	1	14	48	4	16	0	0	0	1	11	42	2
SOUTH DAKOTA																				
Rapid City	22	42	153	18	0	30	83	16	0	8	39	2	20	0	0	0	2	4	31	0
WYOMING																				
Casper	26	48	171	16	0	33	83	12	0	8	49	3	24	0	1	0	2	7	38	1
Lander	21	47	188	22	0	34	90	17	0	15	54	3	19	0	1	0	2	7	43	2
Rock Springs	7	58	196	19	0	44	90	17	0	7	57	1	7	0	1	0	0	7	48	1
Sheridan	26	42	181	23	0	30	89	18	0	17	49	4	24	0	0	0	2	4	43	1

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[1] Read heading as: Mean number of days the maximum temperature was greater than or equal to 90° F. Remaining three headings are read similarly.

TABLE I-8

NORMAL TOTAL HEATING DEGREE DAYS (BASE 65° F)

	ANNUAL	WINTER	SPRING	SUMMER	FALL
MONTANA					
Billings	7049	3531	1825	123	1570
Glasgow	8996	4616	2170	228	1982
Miles City	7723	4052	1912	111	1648
NEBRASKA					
North Platte	6684	3476	1697	63	1448
Scottsbluff	6673	3367	1758	75	1473
Valentine	7425	3808	1912	105	1600
NORTH DAKOTA					
Bismarck	8851	4613	2177	179	1882
Williston	9243	4744	2300	215	1984
SOUTH DAKOTA					
Rapid City	7345	3650	1992	160	1543
WYOMING					
Casper	7638	3644	2052	183	1759
Lander	8303	4056	2128	193	1926
Rock Springs	8473	3988	2288	245	1952
Sheridan	7903	3833	2067	229	1774

The mean freeze free period for the study area varies between 120 and 150 days. This period is defined as the number of days between the last 32°F occurrence in Spring and the first 32°F occurrence in Fall. Freeze free periods and first and last 32°F occurrences are listed for 12 stations in Table I-9. The freeze free period is a good approximation to the length of the growing season. However, the temperature at the soil surface can often be less than the temperature recorded in an instrument shelter several feet above the ground.

May 10 through May 20 marks the last occurrence of 32°F in Spring in the study area. September 10 through September 30 is the range of dates of the first occurrence of freezing temperature. In mountainous areas, such as the Big Horn Mountains, the freeze free period lasts approximately 60 to 90 days.

1.3.3.2. Seasonal Temperatures

Seasonal temperatures show the same spatial variation as the annual, with southern stations recording higher temperatures than northern and mountainous stations.

Figures A-5 through A-8 in the Appendix relate normal, average and extreme seasonal temperatures for selected stations in or near the NGPRP study area. Normal Winter daily minima varied between 4°F and 12°F at these stations, while daily maxima ranged between 23°F and 40°F. Daily averages varied between 14°F and 26°F.

The normals and averages for these NGPRP stations for the remaining three seasons are given below:

Spring

Range of Normal Daily Minima:	28° - 34°F
Range of Normal Daily Maxima:	52° - 60°F
Range of Average Temperatures:	41° - 47°F

Summer

Range of Normal Daily Minima:	51° - 59°F
Range of Normal Daily Maxima	80° - 87°F
Range of Average Temperatures:	66° - 73°F

Fall

Range of Normal Daily Minima:	30° - 36°F
Range of Normal Daily Maxima:	56° - 65°F
Range of Average Temperatures:	42° - 50°F

TABLE I-9

MEAN DATE OF LAST 32^o F TEMPERATURE IN SPRING, FIRST 32^o F IN FALL AND MEAN LENGTH OF FREEZE FREE PERIOD (DAYS)

	Mean Date Last 32^o F in Spring	Mean Date Last 32^o F in Fall	Mean Freeze - Free Period (Days)
MONTANA			
Billings	May 15	Sept 24	132
Glasgow	May 19	Sept 20	124
Miles City	May 5	Oct 3	150
NEBRASKA			
North Platte	April 30	Oct 7	160
Scottsbluff	May 14	Sept 26	135
Valentine	May 7	Sept 30	146
NORTH DAKOTA			
Bismarck	May 11	Sept 24	136
Williston	May 14	Sept 23	132
SOUTH DAKOTA			
Rapid City	May 7	Oct 4	150
WYOMING			
Casper	May 18	Sept 25	130
Lander	May 15	Sept 20	128
Sheridan	May 21	Sept 21	123

1.3.4. Mixing Layer Heights and Upper Air Temperatures

The concept of mixing layer heights appears often in discussions on the ability of the atmosphere to diffuse or disperse pollutants. Basically, the mixing layer height is defined to be the thickness of that layer above the surface within which vertical mixing is enhanced relative to higher layers. Large values for mixing heights indicate a large volume of air through which pollutants can readily disperse. Shallower depths, with less available mixing volume, indicate a more severe meteorologically limiting condition with a greater potential for air pollution.

The mixing height is calculated using surface temperature and temperature measurements as a function of altitude.

Holzworth (1972) investigated mixing heights, average winds through these layers, and the potential for air pollution throughout the continental United States. Results of this study are summarized below.

1.3.3.1. Mixing Heights

Mixing heights for mornings and afternoons were determined using data from 62 U.S. National Weather Service Stations. The morning mixing heights have been calculated considering the urban heat island effect, and consequently the values listed are more correctly referred to as urban morning mixing heights. Urban-rural differences of afternoon mixing heights were assumed to be negligible. Isopleth maps indicating the mean seasonal and annual morning and afternoon mixing heights are shown in Figures I-11 and I-12. The large diurnal variation between the morning and afternoon heights is evident. Table I-10 summarizes the seasonal and annual data relevant to the NGPRP five state study area.

Mean annual morning mixing heights in the study area are generally less than those along the east and west U.S. coasts and by the Great Lakes area. Because of excess moisture and/or low cloudiness in these coastal areas, strong radiation inversions occur less frequently.

Seasonal variation of morning mixing heights in the study area is small, with lower values recorded in summer/autumn, and highest values in spring. Western Montana has higher morning values than surrounding areas.

Mean annual afternoon heights are generally greater in the interior of the United States than along the coasts. The greatest diurnal variation occurs in the Rocky Mountain region.

Seasonal variation of afternoon heights for the study area is much greater than that encountered in the morning. Winter afternoon values are lowest (600-1200 meters), while maximum heights occur in the summer (2000-3200 meters).

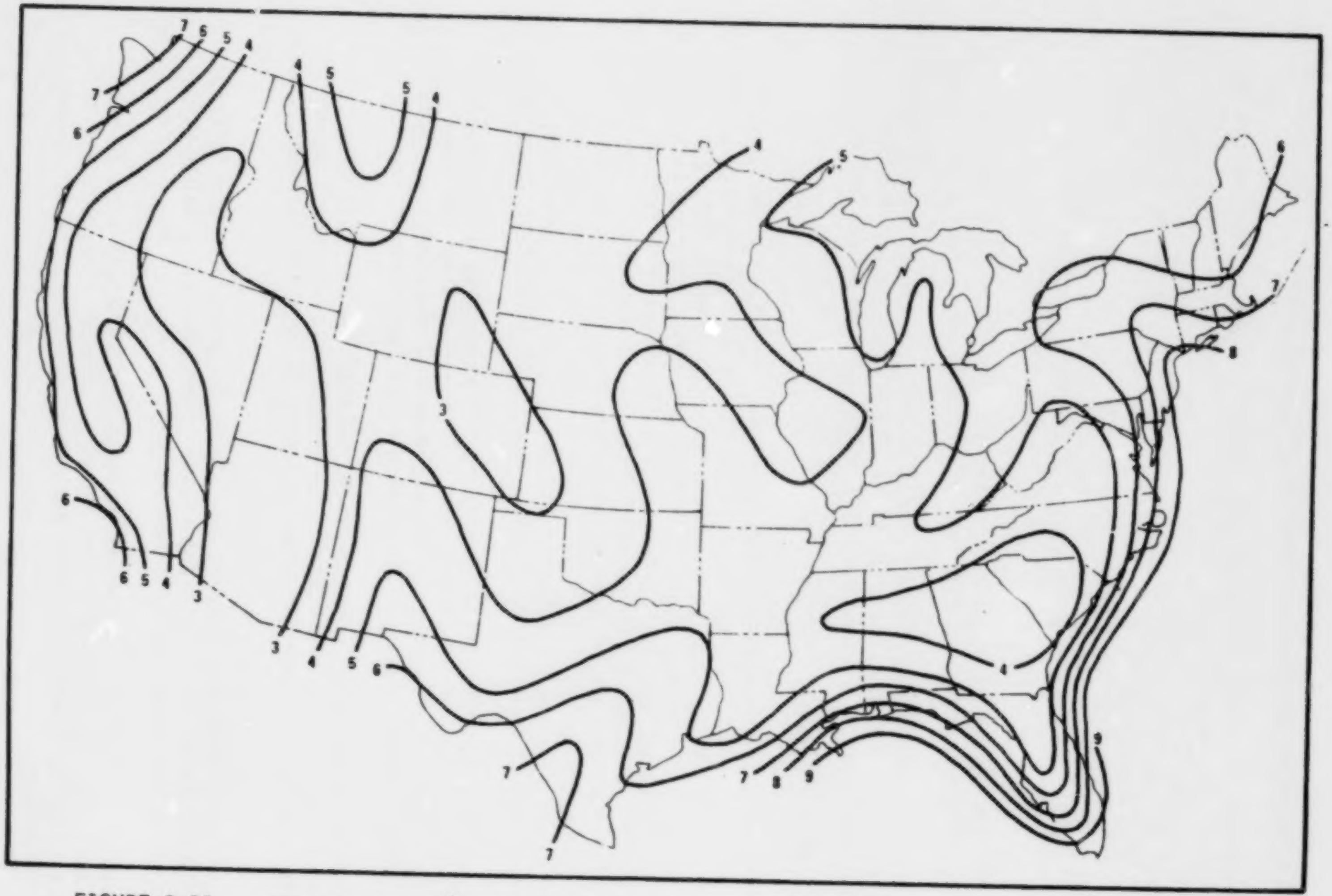
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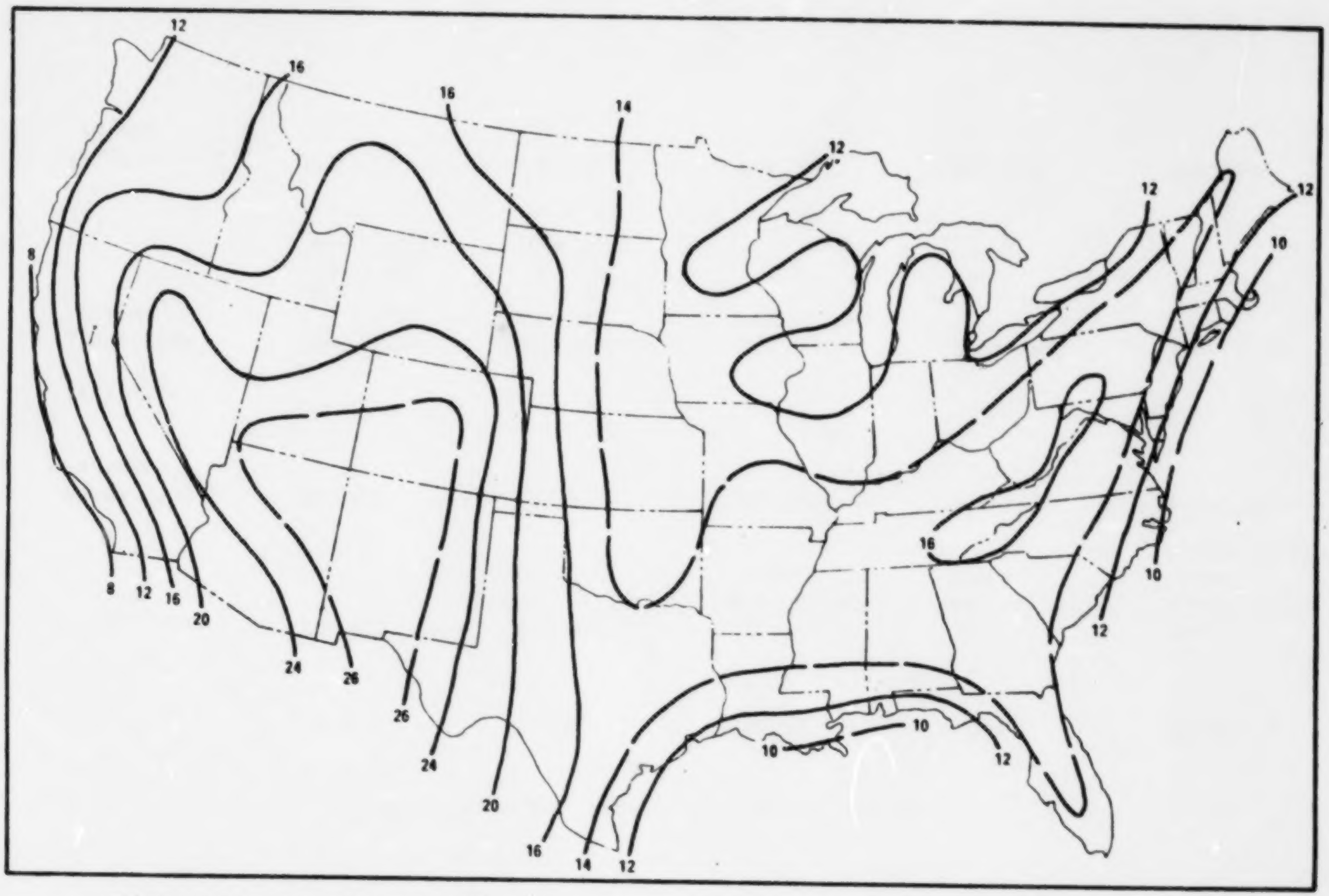
FIGURE I-11. Isopleths (m x 10^2) of mean annual morning mixing heights

(From Holzworth (1972))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12

FIGURE I-12. Isopleths (m x 10^2) of mean annual afternoon mixing heights

(From Holzworth (1972))

TABLE I-10

NGPRP Study Area Mean Mixing Heights (meters)

	Annual	Winter	Spring	Summer	Autumn
Morning					
Study area values	300-400	300-400 500, W. Montana	400-500 600, W. Montana	300 400, W. Montana	300 400 W. Montana 200 SE Wyoming
Range of U.S. values	300-900	200-900	300-1000	200-1300	200-1100
Afternoon					
Study area values	1400-1600, N.D., S.D., Neb. 1600-2400, Mont., Wyo.	600, N.D. 600-1000, N.D., S.D., Montana 1000-1200, Wyoming	2000-2400 2800 S. Wyo.	2000-3200	1400-2000
Range of U.S. values	800-2600	600-1400	800-3400	600-4000	800-2200

1.3.4.2. Wind Speeds

Isopleths of mean annual and seasonal wind speeds were calculated by Holzworth as arithmetic averages of observed wind speeds throughout the mixing layer. Table I-11 presents morning and afternoon mixing-layer wind speeds typical of the NGPRP region. Note that higher mixing layer wind speeds encourage the transport and diffusion of pollutants. Several deductions from this table can be made:

1. Afternoon wind speeds are typically 1-3 m/sec faster than morning values.

2. Highest values occur in western Montana.

3. Lowest values occur in central Wyoming.

4. Summer values are typically less than those calculated for winter.

1.3.5. Air Pollution Potential: Occurrence of Episodes of Restricted Dispersion in the NGPRP Study Area

A combination of a small mixing height and low wind speed in the atmosphere inhibits dispersion of pollutants. Holzworth investigated the frequency of occurrence in the United States of restricted dispersion conditions of varying degrees of severity. Episodes lasting at least two days for various combinations of mixing heights and wind speeds were tallied for a five year time period (1960-64, inclusive). Mixing heights of 500, 1000, 1500 and 2000 meters; and mean mixing layer wind speeds of 2, 4, and 6 meters/sec were considered. Occurrences of episodes lasting at least five days were also tallied. Table I-12 lists the number of episodes of at least two days (for a given mixing height and wind speed), and the total number of episode days occurring in a five year period at NGPRP stations. Some conclusions that can be drawn are:

1. The number of episodes in the West is generally greater than in the Eastern United States.

2. Winter is the season with the greatest frequency of episodes.

3. The number of episodes for Lander, Wyoming is consistently much higher than corresponding values in the study area. Furthermore, frequency of episodes at Lander was generally higher than that at most other stations in the United States with the exception of the West Coast area. The most severely restricted case for dispersion (episodes five days or longer, mixing height 500 m, wind speed $\leq$ 2 m/sec) occurred at only three U.S. weather stations, one of them being Lander.

4. Isopleth diagrams of the number of episode days indicate that Wyoming and Southern Montana have a higher frequency of episodes than

TABLE I-11

Mixing Layer Wind Speeds (meters/sec) for NGPRP Study Area

	Annual	Winter	Spring	Summer	Autumn
Morning					
NGPRP	3-6	3-9	4-7	3-5	3-7
Range of U.S. values	3-7	2-9	3-8	2-7	2-7
Afternoon					
NGPRP	6-9	4-10	7-9	6-7	5-9
Range of U.S. values	4-9	4-10	6-10	5-9	4-9

TABLE I-12

Episodes Lasting 2 or more Days in Five Years

	Wind Speed ≤ 2.0 m/sec				Wind Speed ≤ 4.0 m/sec				Wind Speed ≤ 6.0 m/sec			
Mixing Heights	500m	1000m	1500m	2000m	500m	1000m	1500m	2000m	500m	1000m	1500m	2000m
LOCATION												
BISMARCK, N.D.	0(0)[1]	0(0)	0(0)	0(0)	5(12)[1]	6(15)	8(19)	9(21)	13(39)[1]	20(56)	29(77)	38(99)
GLASGOW, MT.	0(0)	0(0)	0(0)	0(0)	8(21)	8(21)	8(21)	8(21)	27(85)	32(102)	35(108)	39(116)
GREAT FALLS, MT.	0(0)	0(0)	0(0)	0(0)	0(0)	1(3)	2(5)	2(5)	2(5)	7(18)	12(35)	17(48)
LANDER, WYO.	23(71)	30(94)	33(102)	37(112)	42(154)	59(229)	72(283)	84(336)	43(159)	61(241)	75(311)	95(392)
NORTH PLATTE, NEB.	0(0)	0(0)	0(0)	0(0)	3(11)	4(14)	4(14)	6(18)	12(32)	21(52)	32(79)	39(97)
RAPID CITY, S.D.	0(0)	0(0)	0(0)	0(0)	5(16)	5(17)	7(21)	8(23)	7(24)	10(33)	17(48)	28(76)

[1] Left number indicates # of episodes in five years, number in parentheses indicates total number of episode-days. Source: G. Holzworth (1972).

do the western parts of the Dakotas and Nebraska, which in turn has a higher frequency than the eastern parts of the Dakotas and Nebraska.

5. Five day episodes occurred much less frequently than the two day episodes in the NGPRP region, with Lander recording the highest readings.

1.3.6. Precipitation

1.3.6.1. Total Precipitation (Rain, Snow, Ice Pellets, Etc.)

The NGPRP study area is a relatively arid region with normal total precipitation varying from approximately 10 to 19 inches annually in the plains, and over 20 inches in the more mountainous areas. Figure I-13 illustrates the mean annual precipitation in inches by state climatic divisions. Seasonal precipitation maps appear in the Appendix as Figures A-9, A-10, A-11 and A-12.

Southwestern Wyoming recorded the lowest annual rainfall in the study area (10", approximately) with eastern Montana (13" - 14"); western North Dakota (15" - 16"); northeastern Wyoming (16"); western Nebraska (16" - 18"); Black Hills (16" - 24") and Big Horn Mountains (16" - 32") recording greater amounts of precipitation annually.

Nearly 50% of the annual precipitation occurs in the Summer. Winter is the driest season with only 1" - 2" of precipitation in the plains areas and 2" - 4" in the mountainous portions of the study area. Normal seasonal and annual precipitation at 13 stations are listed in Table I-13.

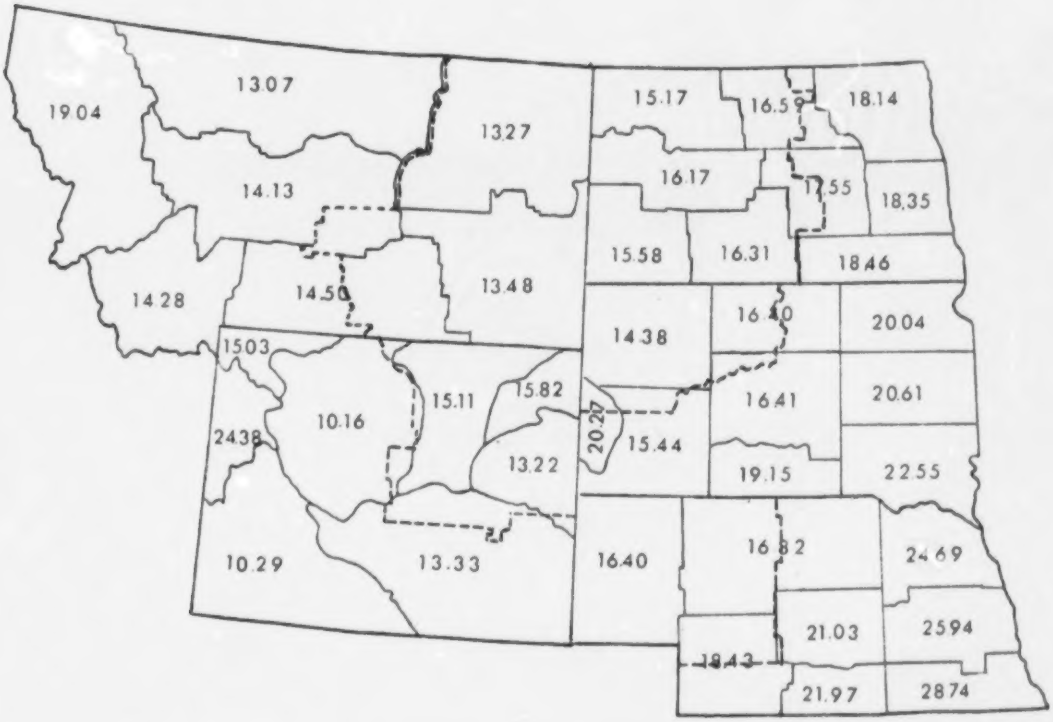
Table I-13 also includes information on the maximum recorded precipitation in a twenty-four hour period for each season. Furthermore, the normal number of days each season and year having 0.01 inch or more of precipitation are tabulated as well. 0.01 inch is usually the minimum detectable fall of precipitation. In an average year, the number of days in the study area with 0.01 inch of rain or more varies between 80 and 120, with the mountainous areas having the more frequent occurrence. Stations in the study area have experienced extreme 24 hour rainfalls of approximately 3" to 6".

1.3.6.2. Snow

Mean annual snowfall in the study area varies generally between 30" and 90". Higher snowfalls are recorded in more mountainous parts of the study area, for example the Big Horn Mountains and the Black Hills record over 200" and 100" annually. The normal seasonal and annual total snowfall (including ice pellets) at selected study area stations appear in Table I-14. Annual snowfalls at these 13 locations ranged between 26.5" and 88.7", with snow falling in Winter, Spring and Fall. The frequency of snowfalls throughout the year is indicated in Table I-14 by the number of days the snowfall is one inch or more. At these 13 stations the number of days of snowfall of one inch or

FIGURE I-13

MEAN ANNUAL PRECIPITATION (inches) BY STATE CLIMATIC DIVISIONS*


19.04
13.07
13.27
15.17
16.59
18.14
14.13
16.17
17.55
18.35
15.58
16.31
18.46
14.28
14.50
13.48
16.40
20.04
14.38
15.03
15.11
15.82
16.41
20.61
24.38
10.16
20.20
15.44
13.22
19.15
22.55
10.29
13.33
16.40
16.82
24.69
21.03
25.94
18.43
21.97
28.74

Based On 24 Years Of Data

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* From: Climatic Atlas of the United States, U.S. Dept. of Commerce. June, 1968.

TABLE 1-13

NORMAL TOTAL PRECIPITATION (INCHES); MEAN NUMBER OF DAYS PRECIPITATION IS .01 INCH OR MORE; AND MAXIMUM RECORDED PRECIPITATION (INCHES) IN 24 HOURS AT SELECTED STATIONS

	ANNUAL			WINTER			SPRING			SUMMER			FALL		
	Total Precip	# Days Precip ≥ .01"	Maximum Precip in 24 hours	Total Precip	# Days Precip ≥ .01"	Maximum Precip in 24 hours	Total Precip	# Days Precip ≥ .01"	Maximum Precip in 24 hours	Total Precip	# Days Precip ≥ .01"	Maximum Precip in 24 hours	Total Precip	# Days Precip ≥ .01"	Maximum Precip in 24 hours
MONTANA															
Billings	13.23	93	2.83	1.73	20	.84	4.24	29	2.83	4.35	25	2.78	2.91	19	1.98
Glasgow	12.27	87	3.98	1.34	22	.37	3.06	21	1.78	5.80	25	3.98	2.07	17	1.00
Miles City	12.83	123	2.71	2.87	38	.77	3.57	33	2.39	3.48	25	2.71	2.91	28	2.67
NEBRASKA															
North Platte	18.27	84	3.80	1.35	14	1.15	5.94	23	2.95	7.90	27	3.80	3.08	15	2.53
Scottsbluff	14.38	84	3.74	1.09	15	.62	5.37	27	2.33	5.56	26	3.74	2.36	16	3.28
Valentine	17.30	78	3.38	1.30	13	.81	5.66	24	2.83	7.72	27	3.38	2.62	13	1.61
NORTH DAKOTA															
Bismarck	15.40	95	4.82	1.19	22	.80	4.09	24	2.86	7.16	30	4.82	2.96	19	4.55
Williston	14.66	89	3.06	1.49	21	.74	3.48	22	2.94	7.13	28	3.06	2.56	18	1.96
SOUTH DAKOTA															
Rapid City	17.46	90	5.57	1.22	29	.85	6.32	29	5.57	7.26	15	3.10	2.66	17	2.76
WYOMING															
Casper	14.09	101	3.09	2.06	18	.58	5.37	32	3.09	3.51	32	1.68	3.15	19	1.80
Lander	14.18	69	3.56	1.60	14	.98	6.12	24	2.43	2.83	18	3.56	3.63	13	1.97
Rock Springs	8.82	84	2.80	1.47	23	.64	2.83	25	1.76	2.23	18	2.80	2.29	18	1.05
Sheridan	16.75	109	3.84	2.03	25	1.10	6.27	36	3.84	4.80	25	3.44	3.65	23	1.38

TABLE I-14

NORMAL TOTAL SNOWFALL[1] (INCHES); MEAN NUMBER OF DAYS SNOWFALL[1] IS 1 INCH OR MORE; AND MAXIMUM RECORDED SNOWFALL[1] (INCHES) IN 24 HOURS AT SELECTED STATIONS

	ANNUAL			WINTER			SPRING			SUMMER			FALL		
	Total Snowfall	# Days Snowfall ≥ 1"	Maximum Snowfall in 24 Hours	Total Snowfall	# Days Snowfall ≥ 1"	Maximum Snowfall in 24 Hours	Total Snowfall	# Days Snowfall ≥ 1"	Maximum Snowfall in 24 Hours	Total Snowfall	# Days Snowfall ≥ 1"	Maximum Snowfall in 24 Hours	Total Snowfall	# Days Snowfall ≥ 1"	Maximum Snowfall in 24 Hours
MONTANA															
Billings	54.7	19	23.7	25.0	9	13.0	19.3	6	23.7	0.1	0	2.0	10.3	3	15.3
Glasgow	26.5	9	8.4	14.4	4	7.4	7.7	2+	8.4	0.0	0	0.0	4.4	2+	4.5
Miles City	49.2	16	11.2	32.7	11	11.2	10.0	3+	6.9	0.0	0	0.0	6.5	2+	6.2
NEBRASKA															
North Platte	31.5	10	9.7	15.4	5	9.7	11.4	3+	9.7	0.0	0	0.0	4.7	2	8.8
Scottsbluff	36.9	12	12.1	16.0	6	7.8	14.1	5+	12.1	0.0	0	0.1	7.0	2	8.5
Valentine	25.4	8	9.0	12.2	4	8.2	9.3	3	9.0	0.0	0	0.0	3.9	1+	8.4
NORTH DAKOTA															
Bismarck	36.9	13	13.5	17.2	6	8.7	12.7	4+	13.5	0.0	0	0.0	6.3	3+	6.6
Williston	32.8	11	10.6	15.8	6	6.6	10.8	3+	10.6	0.0	0	0.0	6.2	2+	8.8
SOUTH DAKOTA															
Rapid City	33.2	10	16.0	13.0	4	9.0	14.8	5+	16.0	0.0	0+	3.0	5.4	1+	9.9
WYOMING															
Casper	70.4	22	20.6	27.2	9	10.4	27.0	8	20.6	0.4	0+	4.5	15.8	5+	11.5
Lander	88.7	22	19.8	27.9	7	19.8	38.0	9	16.1	4.2	0+	18.4	18.6	5+	11.5
Rock Springs	44.6	16	8.9	19.7	7	7.4	15.8	8	7.5	0.3	0+	0.8	8.8	3+	8.9
Sheridan	69.9	23	26.7	30.4	11	11.0	42.0	8+	26.7	0.2	0+	3.2	12.9	4+	12.0

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[1] Includes Snow and Ice Pellets

more varied between 8 (Valentine) and 23 (Sheridan). Sheridan had the greatest 24 hour snowfall of 26.7", while Glasgow had the least (8.4").

1.3.7. Relative Humidity

Relative humidity is a useful index of the moisture content of the atmosphere. Relative humidity at a given temperature is the ratio of the amount of moisture actually present in the air to the amount of moisture the air could hold if saturated at that temperature. This ratio is usually expressed in percent. Because warm air can contain more moisture than cold air, the relative humidity is a function of the air temperature. For example, a relative humidity of 100 at a temperature of 65°F changes to 46 at a temperature of 95°F, assuming no change in the absolute moisture content of the air. Consequently, we expect and actually observe a significant diurnal variation in the relative humidity as the sun exerts its heating influence on the atmosphere. The relative humidity is lowest during the warmest part of the day and highest during the coolest (late evening, and early morning).

Relative humidity may be a significant factor affecting the ease with which pollutants (e.g., SO_2, and photochemical ixidants) react with other atmospheric constituents to form less or more harmful secondary pollutants (e.g., sulfuric acid mist, sulfates, smog, etc.). Relative humidity also has a significant effect on atmospheric visibility.

The mean annual relative humidity for the study area is approximately 60%, with Winter and Fall seasons having higher humidities (approximately 70%) than Summer and Spring. However, there is variation in observed humidities at various sites in the study area. Tabulated in Table I-15 are mean annual and seasonal relative humidities at four times of day (5 a.m., 11 a.m., 5 p.m., 11 p.m.) at 12 sites. The diurnal variation is apparent because the 5 a.m. and 11 p.m. values are much larger than the corresponding 11 a.m. and 5 p.m. values. At 5 a.m., the annual humidities ranged between 66% and 83%, while at 5 p.m., the range was 43% - 60% at these 12 stations.

1.3.8. Clouds and Sunshine

Solar radiation is vital for all animal and plant life on earth. The interaction between air pollutants and solar radiation is therefore significant - an interaction which may produce global as well as local impacts.

Air pollutants can scatter the incoming solar radiation back into space, thus reducing the solar energy available for atmospheric and surface heating. Absorption of solar radiation by gases and aerosols can increase atmospheric heating. The net result of these two processes can be the loss of visible and ultraviolet incoming solar radiation at the surface of a polluted urban site relative to a clean nonurban area (McCormick, 1968).

TABLE I-15

RELATIVE HUMIDITY AT SELECTED STATIONS

	ANNUAL				WINTER				SPRING				SUMMER				FALL			
	5:00 a.	11:00 a. (LOCAL TIME)	5:00 p.	11:00 p.	5:00 a.	11:00 a. (LOCAL TIME)	5:00 p.	11:00 p.	5:00 a.	11:00 a. (LOCAL TIME)	5:00 p.	11:00 p.	5:00 a.	11:00 a. (LOCAL TIME)	5:00 p.	11:30 p.	5:00 a.	11:00 a. (LOCAL .IME)	5:00 p.	11:00 p.
MONTANA																				
Billings	66	51	45	59	65	60	56	64	70	51	44	61	66	43	34	52	65	51	44	57
Glasgow	75	57	52	67	75	72	71	75	76	56	50	68	73	46	37	60	74	55	49	66
Miles City	75	55	50	66	77	70	69	75	78	55	49	70	70	41	33	56	74	53	48	66
NEBRASKA																				
North Platte[1]	83	52	53	76	82	60	66	79	83	51	49	76	84	49	46	74	82	48	52	74
Scottsbluff	76	46	47	68	71	51	56	68	76	45	45	68	80	42	41	69	75	43	46	66
NORTH DAKOTA																				
Bismarck[1]	82	59	60	78	79	71	75	79	82	57	56	77	84	53	50	78	83	56	60	77
Williston[2]	77	55	55	73	75	68	70	75	77	53	51	71	78	46	42	71	79	55	56	73
SOUTH DAKOTA																				
Rapid City	70	50	52	67	70	59	65	70	73	51	52	69	73	46	44	67	65	44	49	61
WYOMING																				
Casper	68	44	44	62	67	56	59	66	74	47	45	69	65	32	28	54	55	42	43	59
Lander	64	46	43	58	66	57	56	65	69	47	44	61	58	36	29	48	64	45	44	57
Rock Springs[3]	69	47	46	60	75	65	65	73	73	47	45	65	61	31	29	44	66	46	44	59
Sheridan	75	50	52	69	73	61	66	72	78	52	52	72	74	40	38	65	74	47	50	68

---

1. Times of Day: 6:00 a., Noon, 6:00 p., Midnight (Local Time)
2. Times of Day: 6:00 a., Noon, 6:00 p., 12:30 a. (Local Time)
3. Times of Day: 5:30 a., 11:30 a., 5:30 p., 11:30 p. (Local Time)

Solar radiation is needed to initiate atmospheric photochemical reactions. This is significant since hydrocarbons and nitrogen oxides (precursors of smog) would be present in the atmosphere if coal gasification plants are constructed in the Northern Great Plains.

The NGPRP study area receives, in an average year, 60% of the possible sunshine. The possible sunshine received is greater in the Summer than in the Winter. Table I-16 indicates the seasonal and annual mean percentage of possible sunshine for nine study area stations.

The study area receives, on the annual average, 350-450 langleys (unit of diffuse and direct solar radiation absorbed on a horizontal surface; 1 langley = 1 gm. cal. cm^{-2}) of solar radiation each day. The daily solar radiation is greater in Summer (approximately 700 langleys) than in Winter (approximately 175 langleys) because of the long Summer days and the greater elevation angle of the sun. Table I-16 lists average daily solar radiation (langleys) for several specific locations.

The mean annual sky cover for the study area is 6 on a scale of 0 to 10, where 0 is interpreted as no clouds or obscuring phenomena and 10 as complete sky cover. Table I-16 gives the seasonal and annual mean sky cover for 13 stations. From this table it is apparent that the least sky cover occurs in the study area in Summer (average sky cover is 4.8) and the greatest cover occurs in Winter and Spring (average sky cover is 6.7).

The mean number of days per year (and per season) of clear, partly cloudy and cloudy skies at selected stations in the study area are listed in Table I-17. For these 13 stations, the average number of clear days per year is 109; the number of partly cloudy days is 114; and the number of cloudy days is 142. The Winter and Spring seasons have a greater frequency of cloudy and partly cloudy days than the Summer season.

1.3.9. Visibility

Measurements of visibility are made at airports, but unfortunately the maximum visibility is not recorded (see Section VIII, 8.3.5). Usually, prevailing visibilities of less than 15 miles are recorded. The Atmospheric Aspects Work Group will compile a summary of available visibility data as part of their 1975 Fiscal Year activities (see Section X).

Table I-18 tabulates the occurrence of heavy fog in the study area which reduces visibility to 1/4 mile or less. The fog data from the 13 stations included in this table indicate an average of 10 days per year of heavy fog and severely reduced visibility. The frequency of heavy fog is greatest in Winter and least in Summer.

TABLE I-15

SUNSHINE AND CLOUDS AT SELECTED STATIONS[1]

	ANNUAL			WINTER			SPRING		
	% of Possible Sunshine	Mean Sky Cover, Sunrise to Sunset	Average Daily Solar Radiation (Langleys)	% of Possible Sunshine	Mean Sky Cover, Sunrise to Sunset	Average Daily Solar Radiation (Langleys)	% of Possible Sunshine	Mean Sky Cover, Sunrise to Sunset	Average Daily Solar Radiation (Langleys)
MONTANA									
Billings	62	6.1	-	50	7.0		60	6.9	-
Glasgow	-	6.4	371	-	7.2	173	-	7.0	453
Miles City	54	6.9	-	31	8.4		53	7.4	-
NEBRASKA									
North Platte	66	5.4	-	59	6.0	-	62	6.4	-
Scottsbluff	-	5.3	-	-	6.0	-	-	6.2	-
Valentine	67	5.7	-	69	6.0	-	60	6.7	-
NORTH DAKOTA									
Bismarck	59	6.1	369	53	6.6	177	58	6.6	451
Williston	64	6.3	-	52	6.9	-	63	6.7	-
SOUTH DAKOTA									
Rapid City	61	5.7	392	56	6.3	206	60	6.5	471
WYOMING									
Casper	-	5.8	-	-	6.4	-	-	6.8	-
Lander	70	5.2	443	67	6.8	249	67	6.1	529
Rock Springs	-	5.8	-	-	6.7	-	-	6.9	-
Sheridan	63	5.9	-	56	6.6	-	59	6.7	-

---

1. Sky cover is expressed in a range of 0 for no clouds or obscuring phenomena to 10 for complete sky cover. Solar radiation data are the average of direct and diffuse radiation on a horizontal surface. The langley denotes one gram calorie per square centimeter.

TABLE I-16 (Cont'd)

SUNSHINE AND CLOUDS AT SELECTED STATIONS

	SUMMER			FALL		
	% of Possible Sunshine	Mean Sky Cover, Sunrise to Sunset	Average Daily Solar Radiation (Langleys)	% of Possible Sunshine	Mean Sky Cover, Sunrise to Sunset	Average Daily Solar Radiation (Langleys)
MONTANA						
Billings	73	4.6	-	59	5.9	-
Glasgow	-	5.1	588	-	6.3	271
Miles City	71	4.8	-	49	6.9	-
NEBRASKA						
North Platte	72	4.6	-	68	4.5	-
Scottsbluff	-	4.5	-	-	4.6	-
Valentine	73	4.9	-	67	5.3	-
NORTH DAKOTA						
Bismarck	69	5.0	574	57	5.9	274
Williston	73	5.5	-	58	6.2	-
SOUTH DAKOTA						
Rapid City	67	4.8	572	62	5.2	430
WYOMING						
Casper	-	4.6	-	-	5.2	-
Lander	75	4.3	638	68	4.6	471
Rock Springs	-	4.7	-	-	5.0	-
Sheridan	70	4.6	-	62	5.5	-

TABLE I-17

MEAN NUMBER OF DAYS OF CLEAR; PARTLY CLOUDY; AND CLOUDY SKIES (SUNRISE TO SUNSET) AT SELECTED STATIONS[1]

	ANNUAL			WINTER			SPRING			SUMMER			FALL		
	Clear	Partly Cloudy	Cloudy	Clear	Partly Cloudy	Cloudy	Clear	Partly Cloudy	Cloudy	Clear	Partly Cloudy	Cloudy	Clear	Partly Cloudy	Cloudy
MONTANA															
Billings	91	119	155	15	26	49	14	29	49	36	36	20	26	28	37
Glasgow	85	106	174	15	21	54	15	27	21	32	34	26	23	24	44
Miles City	101	108	156	18	24	48	16	26	50	38	33	21	29	25	37
NEBRASKA															
North Platte	124	113	128	24	28	38	22	24	46	37	35	20	41	26	24
Scottsbluff	134	107	124	28	26	36	23	28	41	40	32	20	43	21	27
Valentine	115	108	142	28	24	38	20	24	48	34	36	22	33	24	34
NORTH DAKOTA															
Bismarck	100	110	155	21	21	48	18	30	44	33	34	25	28	25	38
Williston	125	117	123	26	24	40	28	31	33	40	34	18	31	28	32
SOUTH DAKOTA															
Rapid City	109	117	139	21	27	42	19	29	44	36	34	22	33	27	31
WYOMING															
Casper	105	116	144	20	26	44	16	29	47	37	33	22	32	28	31
Lander	126	127	112	27	33	30	20	34	38	41	32	19	38	28	25
Rock Springs	102	121	142	18	27	45	16	29	47	32	37	23	36	28	27
Sheridan	101	118	146	19	27	44	16	28	48	37	35	20	29	28	34

---

[1] The number of clear days is based on average cloudiness 0-3, partly cloudy days 4-7, and cloudy days 8-10 tenths.

TABLE I-18

MEAN NUMBER OF DAYS OF THUNDERSTORMS AND HEAVY FOG AT SELECTED STATIONS[1]

	ANNUAL		WINTER		SPRING		SUMMER		FALL	
	Thunder Storms	Fog	Thunder Storms	Fog	Thunder Storms	Fog	Thunder Storms	Fog	Thunder Storms	Fog
MONTANA										
Billings	30	18	0+	5	5+	6	22	1+	2+	5
Glasgow	28	12	0	7	4+	2+	23	0+	1+	2+
Miles City	30	10	0+	5	5+	3	22	0+	2+	2+
NEBRASKA										
North Platte	47	16	0	4	9	4	32	3+	6+	5+
Scottsbluff	46	11	0	3	9+	2+	31	2+	5	3
Valentine	52	8	0	3	9	3	37	1	6	1
NORTH DAKOTA										
Bismarck	37	12	0	3	5+	3+	28	3	4	3
Williston	29	7	0	3	4	1+	23	0+	2+	3
SOUTH DAKOTA										
Rapid City	50	16	0	5	8+	5	37	3+	5+	3
WYOMING										
Casper	38	9	0	2+	9+	3	25	1+	4+	3
Lander	31	2	0	1+	6	0+	22	0+	3+	0+
Rock Springs	40	7	0+	3	8+	2+	27	0+	5+	2+
Sheridan	38	6	0+	3	7	2+	28	0+	3+	1+

---

[1] Heavy fog reduces visibility to 1/4 mile or less.

1.3.10. Other Phenomena

1.3.10.1. Thunderstorms

Thirteen stations in the study area (Table I-18) reported an average of 38 days with thunderstorms per year, with the greatest frequency occurring during the Summer. The mean number of days of thunderstorms in Summer for these stations was 29.

1.3.10.2. Blizzards

Blizzards are severe weather conditions characterized by low temperatures, strong winds and considerable amounts of dry snow. The National Weather Service defines a blizzard to exist when conditions are such that the visibility is less than 500 feet, the temperature less than 20°F and the wind speed greater than 32 miles per hour. Blizzards in the study area usually occur with the passage of a deep low pressure system migrating eastward across the Rocky Mountains. Great Plains blizzards generally result from low pressure systems originating in southern Alberta or southern Colorado. Table I-19 lists the frequency of blizzards by states for a ten year period.

TABLE I-19

Frequency of Blizzards by States for
Years 1957 - 1967 (From Jensen,
Climate of North Dakota)

State	Frequency of Occurrence
Montana	11
Nebraska	17
North Dakota	24
South Dakota	23
Wyoming	2

1.4 NGPRP STUDY AREA EMISSION INVENTORY

Statewide surveys of air emission sources were conducted during 1970 to provide the basis for the control strategies used in the states' implementation plans to meet the National Ambient Air Quality Standards. The results of these surveys, published for the Northern Great Plains states in 1971, are inventories of point and area sources of air pollution. The inventories contain information on the sources' location, the type of emissions (SO_2, particulates, CO, etc.), amount of pollutants emitted, and smoke stack parameters.

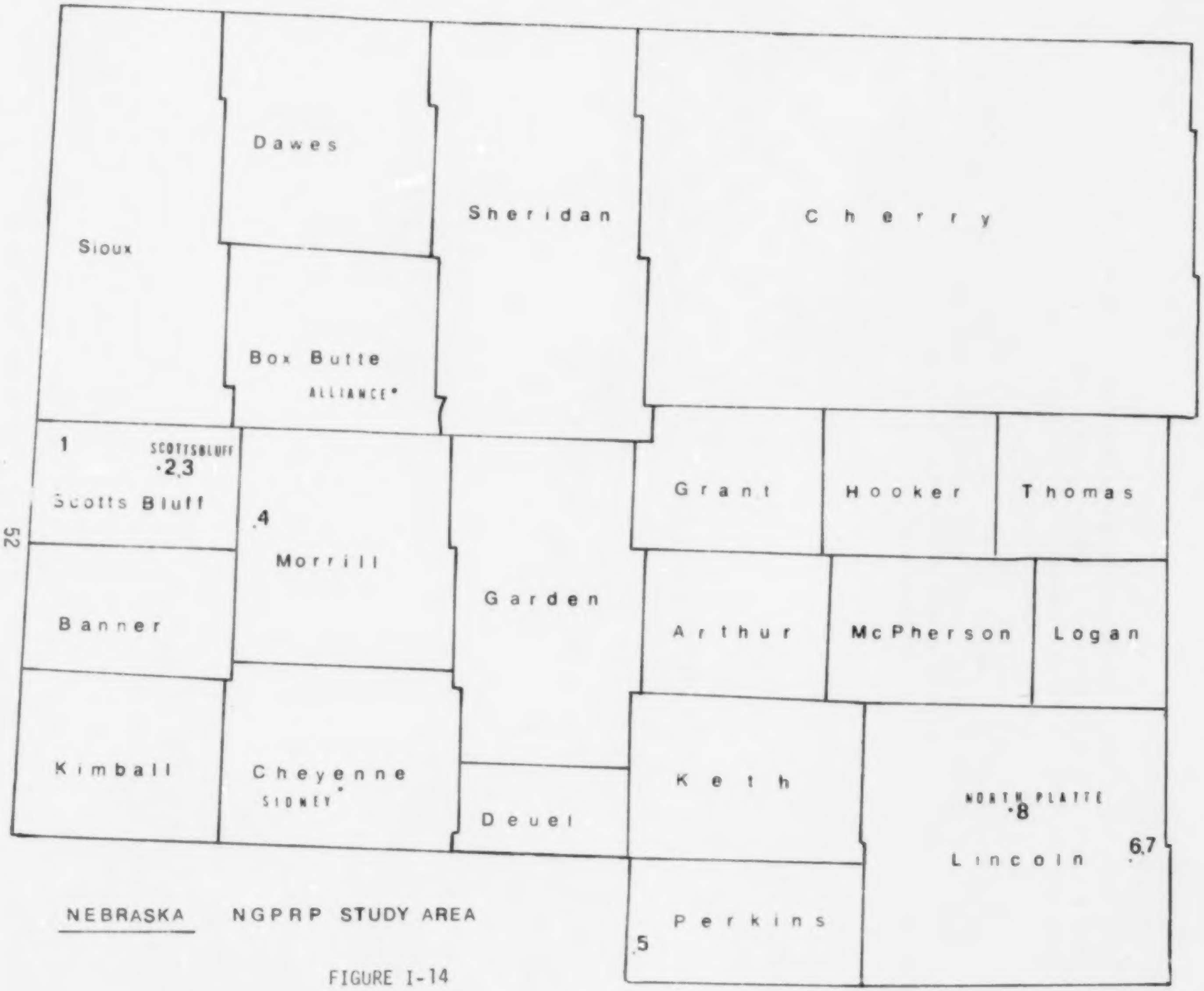
Tables I-20 through I-24 are a portion of the emission inventory for northwestern Nebraska, eastern Montana, western North Dakota, northeastern South Dakota and northeastern and southwestern Wyoming. These tables, in conjunction with the NGPRP state study area maps, (Figures I-14 through I-18) provide (1) the name and location of point sources emitting more than 100 tons per year of particulates and/or SO_2, (2) the number of tons of pollutants emitted per year, and (3) the emissions allowed by state and federal regulations. Many of the inventories were not complete due to the time constraints imposed when the original inventory was done. Thus, the Montana emission inventory may not include every source that emits more than 100 tons per year. However, it is likely that most of the largest sources are listed.

Emission regulations were designed to enable the state to control emissions in order to implement the National Ambient Air Quality Standards and vary from state to state. The magnitude of allowable emissions is a function of specific characteristics of the source. For example, allowable particulate emissions for a source are generally determined by heat input (such as derived from the combustion of fossil fuels) or the total weight of all materials used in the source's process ("process weight"). Sulfur dioxide regulations are typically defined in terms of the sulfur content of the fuels used and SO_2 stack concentrations. The Constraints Section of thie report (Section III) discusses the emission regulations as well as the National Ambient Air Quality Standards in greater detail.

The emission inventory of the study area indicates the existence of a few large emitters, namely, fossil fuel fired power plants and oil refineries, and many smaller sources such as grain elevators. Emission values listed for several older existing power plants in the area indicate the lack of high efficiency pollution control devices. For example, the UPA Stanton Plant, rated at approximately 170 megawatts, emits nearly 14,000 tons of particulates per year. By comparison, the future 330 megawatt Wyodak, Wyoming coal fired power plant will emit in the vicinity of 1000 tons of particulates per year, assuming 99% controls.

"National Emissions Data System" (NEDS), U.S. Environmental Protection Agency.

As a last note, we mention that several other large power plants which might contribute significantly to the region's total emissions are under construction or planned. Jim Bridger (1500 megawatts by 1976) and Utah Power and Light's Naughton Plant (860 additional megawatts by 1977, making a total capacity of 1570 megawatts) are planned for southwestern Wyoming. Colstrip, Montana will have a 660 megawatt capability by 1976, with a possible additional 1400 megawatts by 1979. Furthermore, at least 1850 megawatts are proposed as additions to existing facilities in the Center-Stanton area of North Dakota by 1977. Section IV, Development Scenarios, looks at power plants and gasification plants projected for the Northern Great Plains Region and the estimated magnitude of pollutant emissions.


Sioux
Dawes
Sheridan
Cherry
Box Butte
ALLIANCE
1
SCOTTSBLUFF
2,3
Scotts Bluff
4
Morrill
Garden
Grant
Hooker
Thomas
Arthur
McPherson
Logan
Banner
Kimball
Cheyenne
SIDNEY
Deuel
Keith
NORTH PLATTE
8
Lincoln
6,7
Perkins
5

NEBRASKA NGPRP STUDY AREA

FIGURE I-14

TABLE I-20

NEBRASKA: POINT SOURCES EMITTING MORE THAN 100 TONS/YR OF PARTICULATES AND/OR SO_2

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE[1] * EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
1.	JOHN R. JIRDON	132	--	41	--[4]
	MORRIL	211	--	41	--
2.	GREAT WESTERN SUGAR[3]	193	209	0	0
	SCOTTSBLUFF	193	209	0	0
		1761	286	0	0
		219	238	0	0
3.	CRA, INC. SCOTTSBLUFF	1	131	--	--
4.	GREAT WESTERN SUGAR BAYARD	1948	316	0	0
5.	WESTERN ALFALFA VENANGO	172	--	0	0
6.	KAW DEHY CO., INC. BRADY	225	0	0	0
7	GOTHENBURG FEED PROD. CO., BRADY	180	0	0	0
8.	BIRCHWOOD PRODUCTS NORTH PLATTE	135	0	0	0
	PACIFIC FRUIT EXPRESS[5]	119	0	0	0

* ALL FOOTNOTES CITED AT THE END OF LAST TABLE.

MONTANA NGPRP STUDY AREA

FIGURE I-15

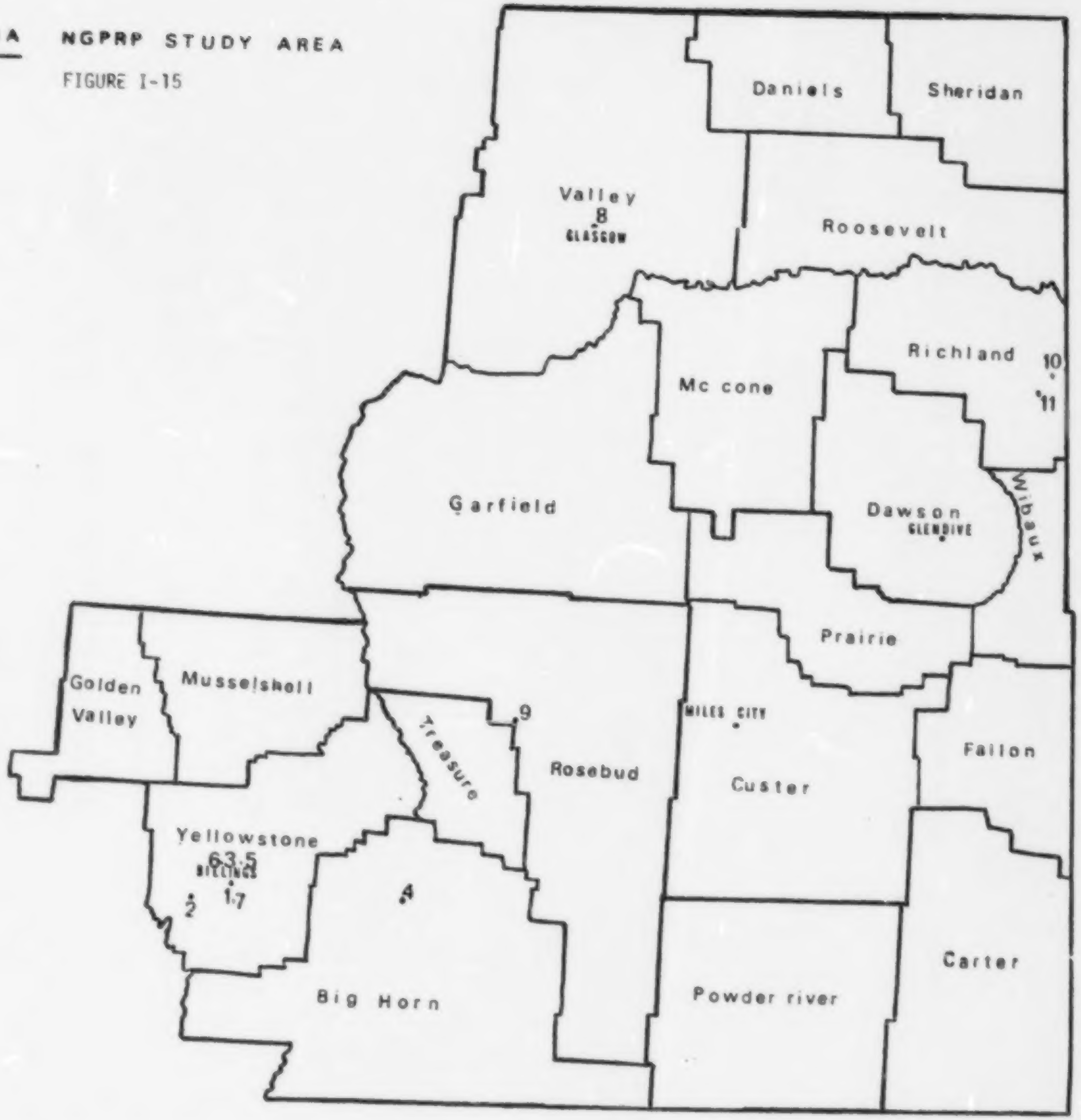

Daniels
Sheridan
Valley
8
GLASGOW
Roosevelt
Richland
10
11
Mc cone
Garfield
Dawson
GLENDIVE
Wibaux
Prairie
Golden Valley
Musselshell
Treasure
9
Rosebud
MILES CITY
Custer
Fallon
Yellowstone
6 3 5
BILLINGS
1 7
2
4
Big Horn
Powder river
Carter

TABLE I-21

MONTANA: POINT SOURCES EMITTING MORE THAN 100 TONS/YR OF PARTICULATES AND/OR SO_2

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR) PART	EMISSIONS (TONS/YR) SO_2	ALLOWABLE[1] EMISSIONS (TONS/YR) PART	ALLOWABLE[1] EMISSIONS (TONS/YR) SO_2
1.	CONTINENTAL OIL	87	2040	200	1130
	BILLINGS	107	1000	196	0
2.	FARMERS UNION CENT/3	18	549	35	230
	LAUREL	35	1097	60	460
		78	672	188	0
		18	550	217	230
		102	3144	308	1320
		--	722	--/4	0
3.	GREAT WESTERN SUGAR BILLINGS	163	--	40	--
4.	HOLLY SUGAR	1544	467	82	458
	HARDIN	40	--	14	--
5.	HUMBLE OIL	--	1270	--	0
	BILLINGS	--	1770	--	0
		195	4755	551	2564
6.	LOVELL CLAY PROD BILLINGS	350	--	20	--
7.	MONTANA POWER CO.	1025	9188	941	6950
	BILLINGS	4	165	27	156
8.	AVCO-ECO SYSTEMS GLASGOW	--	238	--	187
9.	HALLETT MINERALS VANANDA	210	--	67	--

TABLE I-21 (Continued)

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
10.	MONTANA-DAKOTA UTILITIES SIDNEY	3007	4264	635	4230
11.	HOLLY SUGAR SIDNEY	108	--	29	--

NORTH DAKOTA

NGPRP STUDY AREA

FIGURE I-16

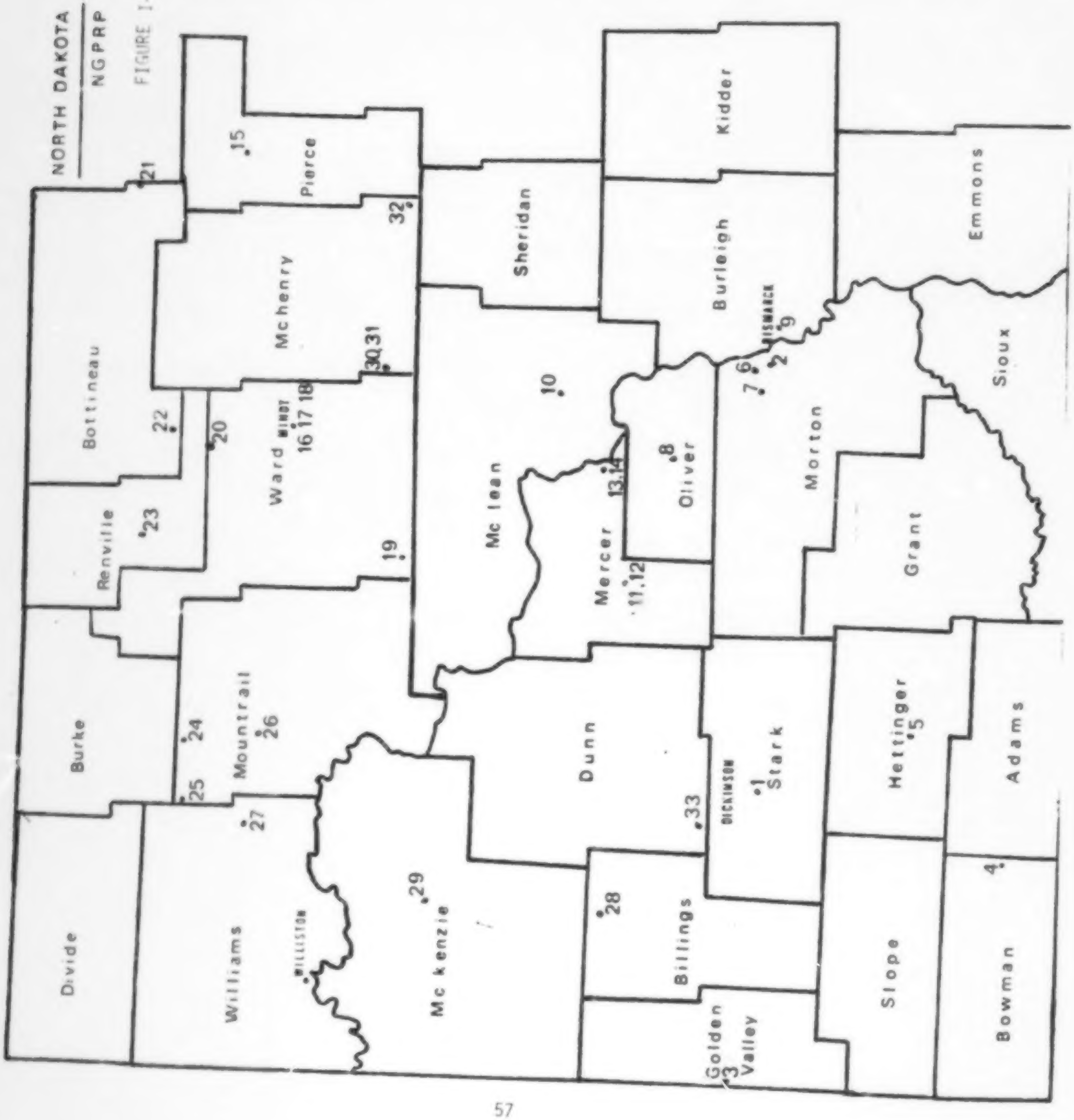

Bottineau
Renville
Burke
Divide
Williams
WILLISTON
Mc kenzie
Mountrail
Ward
MINOT
Mchenry
Pierce
Sheridan
Mc lean
Mercer
Oliver
Dunn
Billings
Golden Valley
Stark
DICKINSON
Hettinger
Slope
Bowman
Adams
Grant
Morton
Sioux
Burleigh
BISMARCK
Kidder
Emmons
1
2
3
4
5
6
7
8
9
10
11,12
13,14
15
16 17 18
19
20
21
22
23
24
25
26
27
28
29
30,31
32
33

TABLE I-22

NORTH DAKOTA: POINT SOURCES EMITTING MORE THAN 100 TONS/YR OF PARTICULATES AND/OR SO_2

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR) PART	SO_2	ALLOWABLE[1] EMISSIONS (TONS/YR) PART	SO_2
1.	HUSKY BRIQUETTING	518	481	40	423
2.	MDU HESKETT MANDAN	3970	7314	2904	10900
3.	GRAIN ELEVATOR BEACH	147	--	15	--[4]
4.	GRAIN ELEVATOR GASCOYNE	172	--	22	--
5.	GRAIN ELEVATOR REGENT	109	--	20	--
6.	AMOCO OIL REFINERY[3] N. OF MANDAN	-- -- -- --	5210 1217 1305 5330	-- -- --	2261 1320 1400 0
7.	BAUKOL-NOONAN NW OF MANDAN	160	--	22	--
8.	MINNKOTA CENTER CENTER	2511	15390	2620	27135
9.	SUPERIOR CONSTRA. BISMARCK	125 22	-- --	20 20	-- --
10.	GRAIN ELEVATOR	128	--	19	--
11.	MDU KNIFE RIVER BEULAH	1134	681	303	1137
12.	MDU DAKOTA BEULAH	420	480	374	1400

TABLE I-22 (Continued)

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
13.	BASIN ELECTRIC STANT. STANTON	9792	12164	1836	18000
14.	UPA STANTON STANTON	13768	13413	2600	26613
15.	GRAIN ELEVATOR RUGBY	248	--	23	--
16.	NSP MINOT MINOT	970	460	374	862
17.	MINOT PAVING MINOT	1575	--	68	--
18.	MINOT ST COLL MINOT	--	106	--	161
19.	GRAIN ELEVATOR SW RYDER	180	--	24	--
20.	MINOT AFB	579	345	231	869
21.	GRAIN ELEVATOR OVERLY	130	--	15	--
22.	GRAIN ELEVATOR	163	--	24	--
23.	GRAIN ELEVATOR GRANO	114	--	13	--
24.	GRAIN ELEVATOR	112	--	14	--
25.	HUNT IND.	--	370	--	0
26.	GRAIN ELEVATOR STANLEY	200	--	20	--
27.	SIGNAL GAS REFINERY	--	4550	--	0
28.	GRAIN ELEVATOR	104	--	21	--
29.	GRAIN ELEVATOR WATFORD CITY	150	--	16	--

TABLE I-22 (Continued)

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
30.	CENTRAL POWER	2328	2364	638	4910
31.	CONSOLIDATION CL	1256	--	46	--
32.	GRAIN ELEVATOR ANAMOOSE	102	--	20	--
33.	FISCHER S-G	405	--	48	--

SOUTH DAKOTA NGPRP STUDY AREA

FIGURE I-17

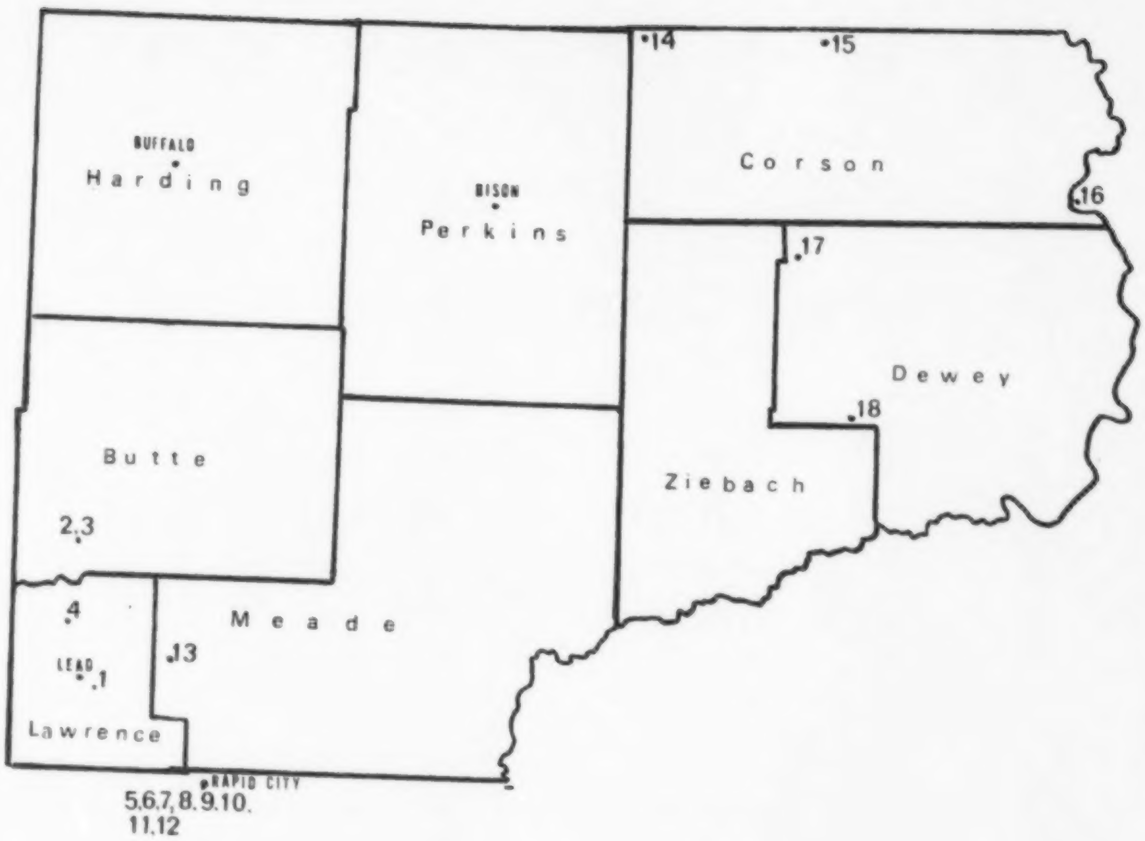

Harding
BUFFALO
Perkins
BISON
Corson
Dewey
Ziebach
Butte
Meade
Lawrence
LEAD
RAPID CITY
1
2,3
4
5,6,7,8,9,10,
11,12
13
14
15
16
17
18

TABLE I-23

SOUTH DAKOTA: POINT SOURCES EMITTING MORE THAN 100 TONS/YR OF PARTICULATES AND/OR SO_2

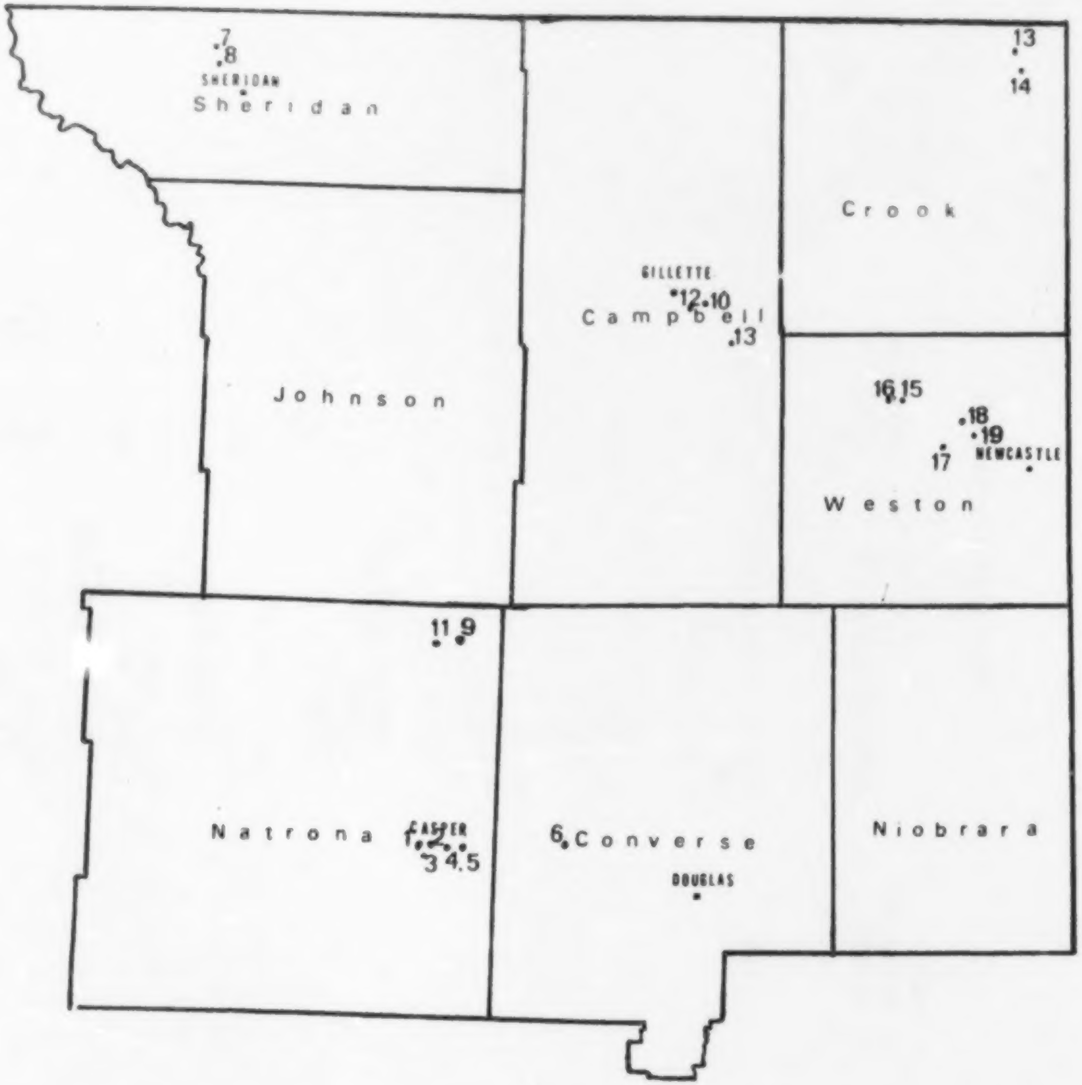
MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE[1,2] EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
1.	BLACK HILLS POWER &[3] LIGHT, KIRK PLANT LEAD	192	40	665	6550
		337	70	0	0
		416	87	0	0
		1083	471	0	0
2.	BLACK HILLS CLAY BELLE FOURCHE	350	--	86	--[4]
3.	AMER. COLLOID BELLE FOURCHE	225	--	54	--
		180	--	46	--
		450	--	86	--
		180	--	46	--
4.	ASPHALT-LEE CONST. SPEARFISH	105	--	9	--
5.	S. OAK CEMENT PLANT RAPID CITY	145	3825	217	9-
6.	SUMMIT, INC. RAPID CITY	501	--	501	--
7.	L. G. EVERIST, INC. NW OF RAPID CITY	1135	--	78	--
8.	PETE LIEN & SONS QUARRY RAPID CITY	7760	--	306	--
9.	PETE LIEN & SONS LIME RAPID CITY	1200	--	161	--

TABLE I-23 (Continued)

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
10.	LIGHT AGGREGATES, INC. RAPID CITY	241	--	35	--
11.	S. DAKOTA DEPT. OF HIGHWAYS RAPID CITY	100	--	100	--
12.	BLACK HILLS POWER & LIGHT BEN FRENCH RAPID CITY	725	613	356	3564
13.	S. DAKOTA DEPT. OF HIGHWAYS STURBIS	234	--	234	--
14.	FARMERS GROUP ASSOC. THUNDER HAWK	440	--	122	--
15.	J. L. HEALY CONSTR. CO. 10 M.S. MC INTOSH	467	--	584	--
16.	MONTANA UTILITIES MOBRIDGE	185 185	271 271	105 0	1048 0
17.	S. DAKOTA DEPT. OF HIGHWAYS ISABEL	112	--	117	--
18.	EAGLE BUTTE COOP EAGLE BUTTE	100	--	67	--

WYOMING NGPRP STUDY AREA

FIGURE I-18 A


Sheridan
SHERIDAN
7
8
Johnson
Campbell
GILLETTE
12
10
13
Crook
13
14
Weston
16
15
18
19
17
NEWCASTLE
Natrona
CASPER
1
2
3
4
5
11
9
Converse
6
DOUGLAS
Niobrara

W Y O M I N G

FIGURE I-18 B

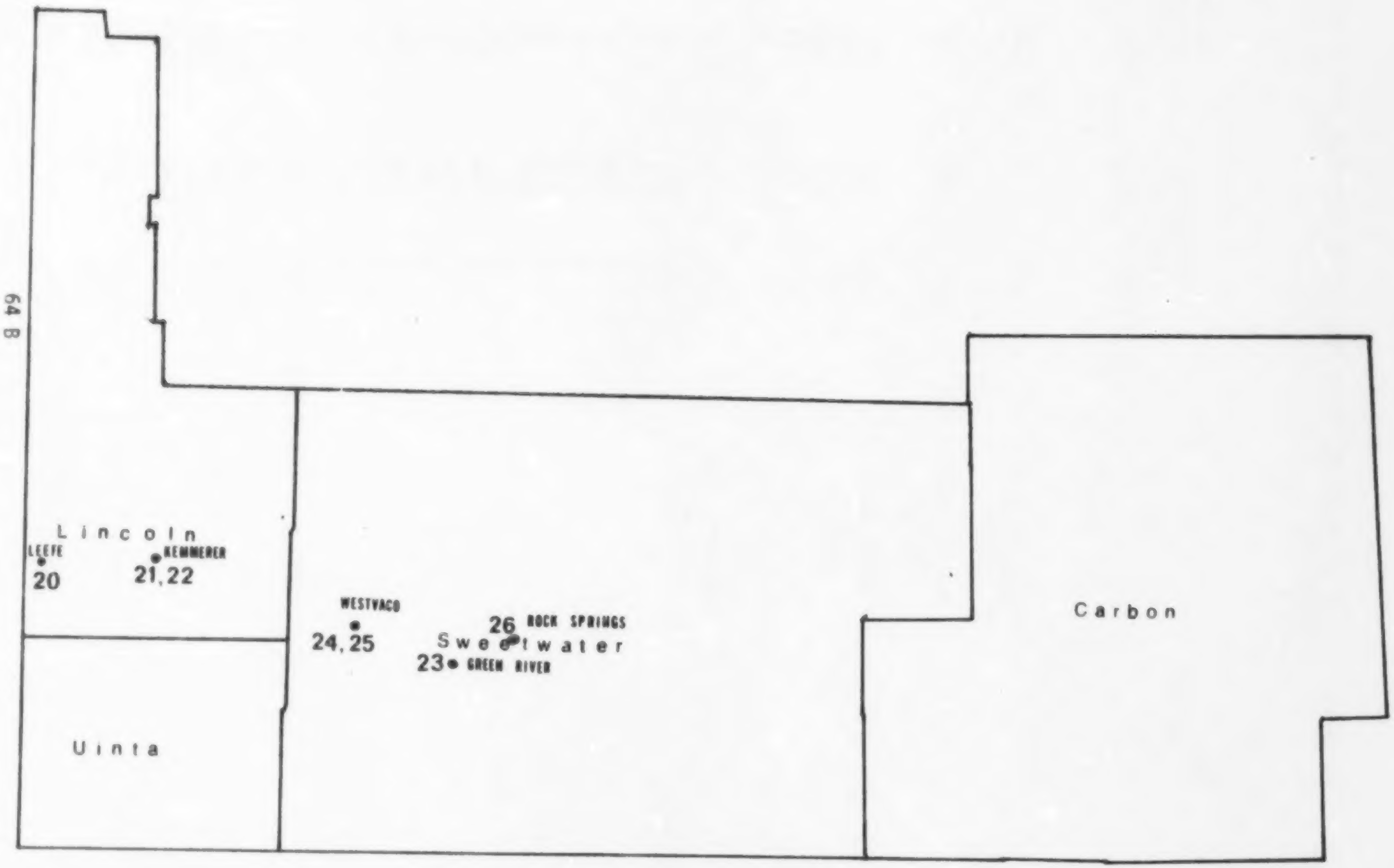

Lincoln
LEEFE
20
KEMMERER
21,22
Uinta
WESTVACO
24,25
26 ROCK SPRINGS
Sweetwater
23 GREEN RIVER
Carbon

TABLE I-24

WYOMING: POINT SOURCES EMITTING MORE THAN 100 TONS/YR OF PARTICULATES AND/OR SO_2

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE[1,2] EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
1.	BENTON CLAY MILLS	150	0	35	0[2]
2.	GREAT LAKES C CO. CASPER	221	257	69	9-
3.	AMERICAN OIL/[3]	21	225	268	9-
	CASPER	21	225	268	9-
		21	225	268	9-
		172	464	197	9-
		0	1040	0	9-
4.	TEXACO, INC.	22	482	250	9-
	EVANSVILLE	23	505	250	9-
		23	494	260	9-
		24	529	260	9-
		4	236	87	9-
		2	118	49	9-
		2	138	54	9-
		2	3040	76	9-
		2	171	66	9-
		5	244	310	9-
		3	200	81	9-
		2	126	70	9-
		4	226	124	9-
		110	2100	192	9-
		0	1081	0	9-
5.	LITTLE AMERICA OIL	124	1706	227	9-
6.	PPL	5020	4770	1128	9-
	GLENROCK	5850	4920	1128	9-
		7580	6240	2322	9-
		100	3680	3344	9-
7.	MONTANA-DAKOTA	1729	500	102	9-
	UTILITIES SHERIDAN	132	38	742	9-

TABLE I-24 (Continued)

MAP REFERENCE NUMBER	NAME AND LOCATION	EMISSIONS (TONS/YR) PART	EMISSIONS (TONS/YR) SO_2	ALLOWABLE EMISSIONS (TONS/YR) PART	ALLOWABLE EMISSIONS (TONS/YR) SO_2
8.	BIG HORN GYPSUM	244	0	109	0
	BIG HORN	106	0	109	0
9.	MONOLITH PORTLAND	62	3414	127	9-
	MIDWEST	301	5	62	0
10.	BLACK HILLS POWER	474	75	44	9-
	& LIGHT	315	63	38	9-
	WYODAK	729	580	269	9-
11.	CON AGRA HWY 87 & 14	100	0	23	0
12.	WYODAK RESOURCE DEVELOPMENT WYODAK	647	0	45	0
13.	FED BENTONITE CROOK	382	1	121	9-
14.	INTER MINERALS & CHEMICALS COLONY	1080	0	131	0
15.	AMERICAN COLLOID	1013	0	158	0
	UPTON	176	0	157	9-
16.	FED BENTONITE	442	0	75	9-
	UPTON	303	0	75	9-
17.	BAROID DIVISION OSAGE	291	0	112	0
18.	BLACK HILLS POWER	126	290	49	9-
	& LIGHT	125	290	51	9-
	OSAGE	125	289	51	9-
		105	2	3	9-
19.	TESORO PETR CO	252	288	155	9-
	NEWCASTLE	79	109	64	9-

TABLE I-24 (Continued)

SOUTHWESTERN WYOMING

	NAME AND LOCATION	EMISSIONS (TONS/YR)		ALLOWABLE EMISSIONS (TONS/YR)	
		PART	SO_2	PART	SO_2
20.	STAUFFER LEEFE LEEFE	385	--	115.3	9-
21.	UTAH POWER & LIGHT S.W. OF KEMMERER	1897	2772	703.4	9-
22.	FMC KEMMERER S.W. OF KEMMERER	871	--	89.7	9-
23.	STAUFFER CHEMICAL N.W. OF GREEN RIVER	258	--	303.0	9-
24.	FMC SODA WESTVACO	353	35	412.5	9-
25.	ALLIED CHEMICAL S.E. OF WESTVACO	1893	--	300.7	9-
26.	GUN QUEELY COAL S. OF ROCK SPRINGS	797	--	10.5	9-

FOOTNOTES:

1. "0" in Allowable column indicates emission regulations not applicable.
2. "9-" in Allowable column indicates no emission regulation.
3. Emissions from multiple sources at a given site, e.g., several stacks belonging to the same power plant, are listed.
4. Allowable Emissions not specified in NEDS listing.
5. Specific source location not listed in NEDS inventory.

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SECTION II

NGPRP ATMOSPHERIC ASPECTS DATA ACQUISITION NETWORK

2.1 OBJECTIVES

The Regional Profile Report (Section I) indicated the lack of ambient air quality and meteorological data in the rural areas of Montana, Wyoming and the Dakotas where large power and gasification plants may ultimately be sited. In concert with one of the fundamental objectives of the NGPRP, namely to provide needed data and analytical models enabling assessments of the consequences of various courses of action to be made, the Atmospheric Aspects Work Group has designed a network to acquire the necessary baseline air quality and meteorology data.

Specific objectives of the data collection network are:

1. To acquire regional baseline air quality data that is presently unavailable. Ambient concentrations of SO_2, NO_x and particulates (including sulfates, nitrates, flourides, trace elements, and particulate sizes) will be determined.
2. To acquire regional baseline meteorology data required for mathematical models that describe the diffusion of air pollutants. Surface wind speed and direction; temperature, wind speed and direction as a function of altitude will be measured.
3. To acquire this data for a minimum of twelve months. Monitoring is expected to continue at selected sites for more than one year.
4. To make this body of data available to decision makers at all levels.

2.2 AIR QUALITY SAMPLING

Several types of air quality samplers will be used in the field. Table II.1 summarizes the sampling equipment employed and the nature of the information resulting from the reduced data. Figure II-1 is a map indicating sampling site locations, as well as the meteorology network, while Table II-2 lists the twenty-three different sites and the instruments located there. For comparison, Figures II-2 and II-3 show the existing study area data stations and the combined NGPRP and existing networks.

TABLE II-1

NGPRP ATMOSPHERIC ASPECTS MONITORING NETWORK

EQUIPMENT	OBJECTIVE	SAMPLING FREQUENCY	ANALYSES
1. High Volume Samplers (26 units)	Acquire background data on concentrations of total suspended particulates; trace elements; sulfates: nitrates; fluorides.	Twenty-four hour samples collected once every six days.	Concentrations of total suspended particulates; trace elements; sulfates; nitrates; fluorides.
2. Membrane Samplers (5 units)	Acquire trace element data from filters with low background concentrations of elements of interest.	Twenty-four hour samples collected once every six days.	Concentrations of trace elements in particulate matter.
3. Cascade Impactors (3 units)	Acquire data on particle size of suspended particulate matter; acquire data on trace element concentration as a function of particle size.	Twenty-four hour samples collected once every six days.	Mass and trace element concentrations as a function of particle size.
4. Gas Bubblers (5 units)	Acquire SO_2, NO_2 data. Backup to the continuous analyzers.	Twenty-four hour samples collected once every six days.	24 hour SO_2, NO_2 concentrations.
5. Continuous Analyzers (2 SO_2 units) (2 NO_x units)	Acquire SO_2, NO, NO_2 data continuously.	Data collected continuously.	Short term concentrations of SO_2, NO, NO_2.

FIGURE II-1

NGPRP AIR QUALITY AND METEOROLOGICAL NETWORK

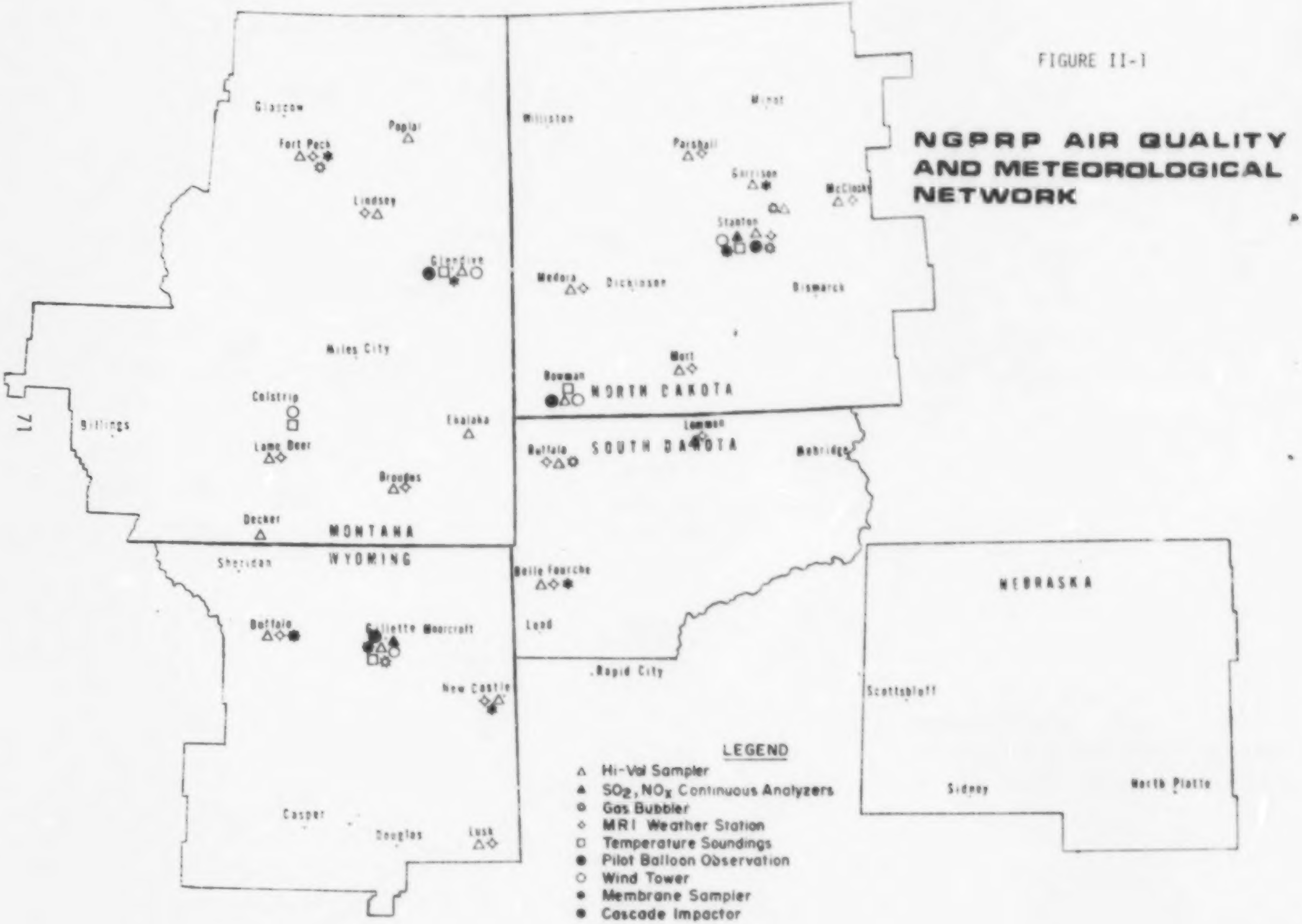
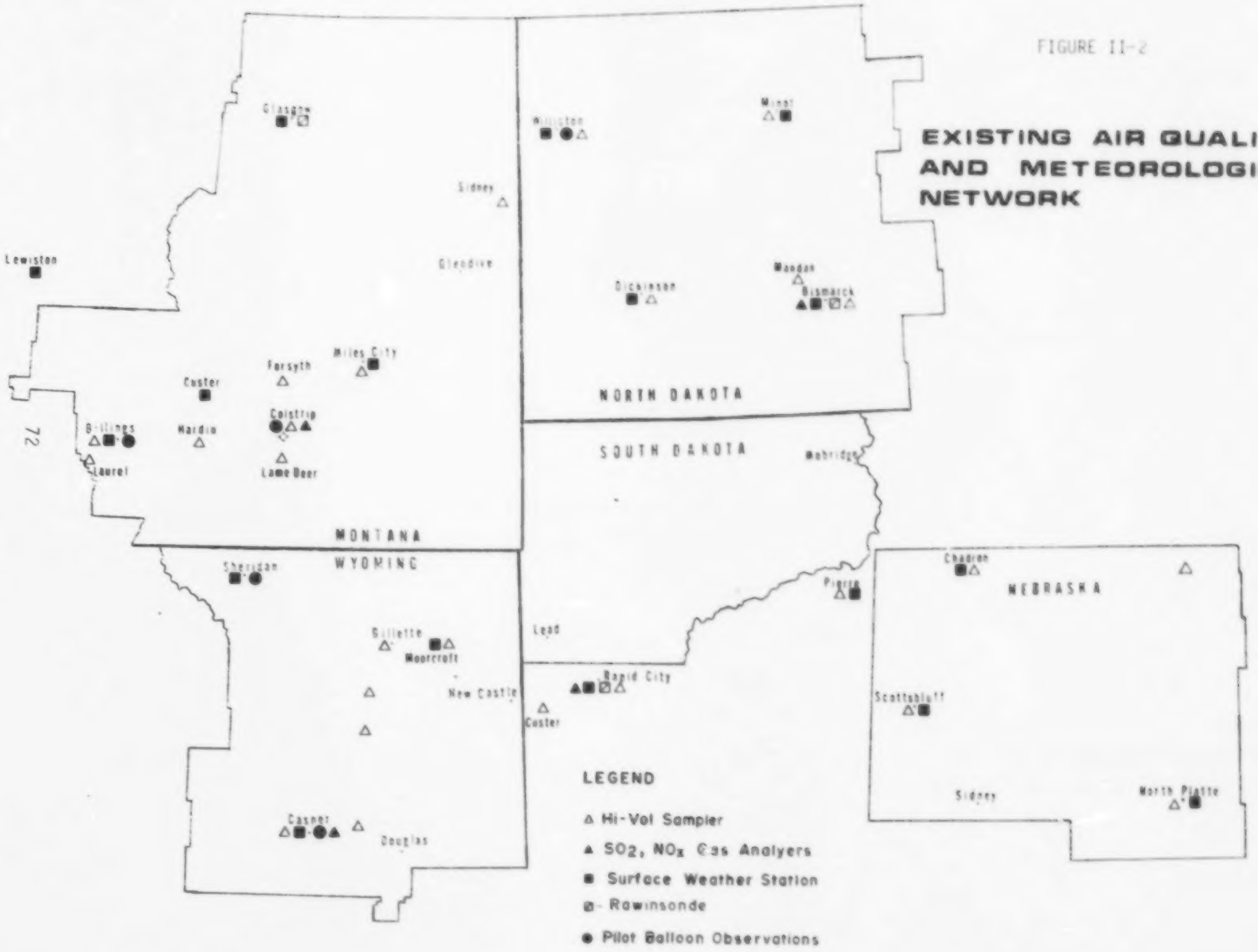

MONTANA
WYOMING
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
Glasgow
Fort Peck
Poplar
Lindsey
Glendive
Miles City
Colstrip
Lame Deer
Ekalaka
Broadus
Decker
Billings
Sheridan
Buffalo
Gillette
Moorcroft
New Castle
Casper
Douglas
Lusk
Williston
Minot
Parshall
Garrison
McClusky
Stanton
Medora
Dickinson
Bismarck
Mott
Bowman
Lemmon
Buffalo
Mobridge
Belle Fourche
Lead
Rapid City
Scottsbluff
Sidney
North Platte
LEGEND
△ Hi-Vol Sampler
▲ SO_2, NO_x Continuous Analyzers
⚙ Gas Bubbler
◇ MRI Weather Station
□ Temperature Soundings
● Pilot Balloon Observation
○ Wind Tower
✱ Membrane Sampler
● Cascade Impactor

FIGURE II-2

EXISTING AIR QUALITY AND METEOROLOGICAL NETWORK



MONTANA
NORTH DAKOTA
SOUTH DAKOTA
WYOMING
NEBRASKA
Lewiston
Glasgow
Sidney
Glendive
Miles City
Forsyth
Custer
Colstrip
Billings
Hardin
Laurel
Lame Deer
Williston
Minot
Dickinson
Mandan
Bismarck
Mobridge
Pierre
Lead
Rapid City
Custer
Sheridan
Gillette
Moorcroft
New Castle
Casper
Douglas
Chadron
Scottsbluff
Sidney
North Platte
LEGEND
△ Hi-Vol Sampler
▲ SO_2, NO_x Gas Analyers
■ Surface Weather Station
⌀- Rawinsonde
● Pilot Balloon Observations

FIGURE II-3

COMBINED NGPRP & EXISTING AIR QUALITY AND METEOROLOGICAL NETWORK

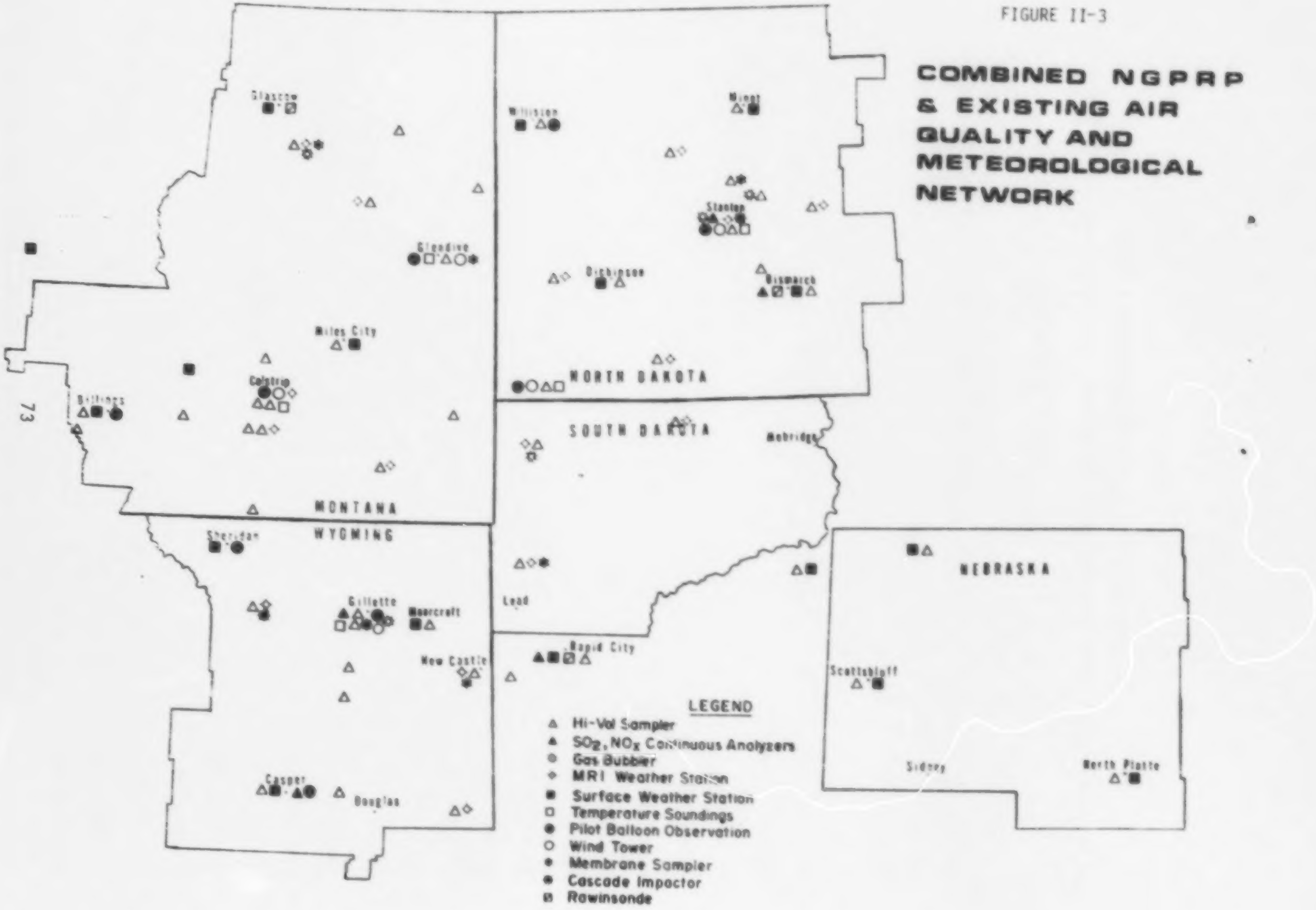

Glasgow
Glendive
Miles City
Colstrip
Billings
MONTANA
WYOMING
Sheridan
Gillette
Moorcroft
New Castle
Casper
Douglas
Williston
Minot
Stanton
Dickinson
Bismarck
NORTH DAKOTA
SOUTH DAKOTA
Mobridge
Lead
Rapid City
NEBRASKA
Scottsbluff
Sidney
North Platte
LEGEND
△ Hi-Vol Sampler
▲ SO_2, NO_x Continuous Analyzers
◎ Gas Bubbler
◇ MRI Weather Station
■ Surface Weather Station
□ Temperature Soundings
● Pilot Balloon Observation
○ Wind Tower
✱ Membrane Sampler
✹ Cascade Impactor
⊠ Rawinsonde

TABLE II-2

NGPRP ATMOSPHERIC ASPECTS MONITORING NETWORK

	INSTRUMENTS						
LOCATION	Hi-Vol	Membrane	MRI Station	SO_2-NO_x Continuous	SO_2-NO_2 Bubbler	Cascade Impactors	Pilot Balloon OBS; T-Sondes; Wind Towers
Buffalo, WY	X		X			X	
Gillette, WY	X			X	X	X	X
Lusk, WY	X		X				
Newcastle, WY	X	X	X				
Belle Fourche, SD	X	X	X				
Buffalo, SD	X		X		X		
Lemmon, SD	X		X				
Parshall, ND	X		X				
Garrison, ND	X	X					
Washburn, ND	X				X		
McClusky, ND	X		X				
Bowman, ND	X						X
Stanton, ND	X		X	X	X	X	X
Mott, ND	X		X				
Medora, ND	X		X				
Lame Deer, MT	X		X				
Broadus, MT	X		X				
Ekalaka, MT	X						
Glendive, MT	X	X	X				X
Lindsay, MT	X						
Poplar, MT	X		X				
Ft. Peck, MT	X	X	X		X		
Colstrip, MT							X

Data collection at the Montana Stations (with the exception of Lame Deer) began in March, 1974. The remaining stations will begin their operation during June, 1974. All stations will remain in operation for at least twelve months. It is anticipated that a number of these stations will continue sampling past one year and that new sampling sites will be added in other parts of the NGPRP study area.

2.2.1 High-Volume Samplers (Hi-vols)

Twenty-six high volume samplers will be located at twenty-two different sites in the study area. Four stations will have duplicate high volume samplers as part of the data quality assurance program. The samples will be operated continuously for a 24-hour period (midnight to midnight), once every six days according to the National Air Surveillance Network (NASN) sampling schedule (Table II-3). Through various physical and chemical procedures, the particulate matter captured on the high volume filters will be analyzed for mass concentrations (i.e., mass of pollutant per unit volume of ambient air) of total suspended particulates, sulfates, nitrates, flourides and numerous trace elements. The initial trace element investigations will be semi-quantitative and will detect the presence of some fifty-three elements of interest in suspended particulate matter. Spark source mass spectrometry will be the analytical tool for this analysis. Table II-4 is a listing of these elements of interest. Section 2.3, Air Quality Data Reports, discusses the planned reduction and analysis for hi-vol and other air quality sampler data.

2.2.2 Membrane Samplers

Five membrane samplers are being used in this network. The special membrane filters used by this sampler have low background concentrations of trace elements, and will serve as a backup to the high-volume sampler filters in the event of anomalous hi-vol trace element concentrations. Membrane samplers operate on the same 24-hour/6-day schedule as the high volume samplers.

2.2.3 Cascade Impactors

Three cascade impactors will collect data on the size of suspended particulate matter. This device fractionates the particulate matter according to five size ranges varying between .01 and 40 microns (1 micron = one millionth of a meter). The analysis of each cascade stage for trace elements will provide information on the relationship between particle size and trace element concentration. Furthermore, particle size data is relevant to discussions of visibility, since it is those particles of less than 1 micron radius that are primarily responsible for scattering of light.

Impactors operate on the same 24-hour/6-day schedule as the high volume samplers. Depending on the initial results, these instruments may be run for 36 or 48 hours in order to accumulate enough sample for analysis.

TABLE II-3

NATIONAL AIR SURVEILLANCE NETWORK

HI-VOL SAMPLING SCHEDULE

Spring Quarter						
	March	6	April	5	May	5
	(1974)	12		11		11
		18		17		17
		24		23		23
		30		29		29
Summer Quarter						
	June	4	July	4	August	3
		10		10		9
		16		16		15
		22		22		21
		28		28		27
Fall Quarter						
	September	2	October	2	November	1
		8		8		7
		14		14		13
		20		20		19
		26		26		25
Winter Quarter						
	December	1	January	6	February	5
		7	(1975)	12		11
		13		18		17
		19		24		23
		25		30		
		31				
Spring Quarter						
	March	1	April	6	May	6
		7		12		12
		13		18		18
		19		24		24
		25		30		30
		31				

TABLE II-4

TRACE ELEMENTS OF INTEREST

Metals

Aluminum
Antimony
Arsenic
Barium
Beryllium
Bismuth
Boron
Cadmium
Calcium
Cerium
Chlorine
Chromium
Cobalt
Copper
Fluorine
Gallium
Germanium
Iron

Metals

Lanthanum
Lead
Lithium
Magnesium
Manganese
Mercury
Molybdenum
Nickel
Osmium
Palladium
Phosphorus
Platinum
Potassium
Radium
Rhenium
Rhodium
Rubidium
Ruthenium

Metals

Scandium
Selenium
Silicon
Silver
Sodium
Strontium
Sulfur
Thallium
Thorium
Tin
Titanium
Uranium
Vanadium
Ytterbium
Yttrium
Zinc
Zirconium

2.2.4 Gas Bubblers

Five gas bubblers in the air quality network will provide intermittant long term (24-hour) concentrations of SO_2 and NO_2. Bubblers also operate on the same 24-hour/6-day schedule as the high volume samplers.

2.2.5 Continuous Gas Analyzers

Two SO_2 and two NO/NO_2 gas analyzers will continuously record gas concentrations at Gillette, Wyoming and Stanton, North Dakota. A third station, at Colstrip, Montana is operated by the State of Montana. Hourly averages of SO_2, NO and NO_2 will be determined from the raw continuous data.

2.3 AIR QUALITY DATA REPORTS

The Atmospheric Aspects Work Group will issue periodic reports summarizing the data output of the air quality network. The quarterly and annual reports will be widely distributed. Information contained in the monthly reports will be available on request.

2.3.1 Monthly Reports

Monthly reports will include the following:

2.3.1.1 A brief status report for each station.

2.3.1.2 A tabulation of all raw data for the month:

1. List of total suspended particulate, sulfate, nitrate and fluoride concentrations determined from each hi-vol filter for each station.
2. List of 24-hour SO_2-NO_2 concentrations (gas bubblers).
3. List of 1-hour SO_2, NO and NO_2 concentrations (continuous analyzers).
4. List of concentrations of particulate matter according to size range (cascade impactors).
5. Trace element analyses will be done on quarterly basis only.

2.3.1.3 Data anomaly reports for all total suspended particulate samples having concentrations greater than 150 ug/m^3 and all SO_2, NO, NO_2 data greater than 0.1 ppm for a one-hour average.

2.3.2 Quarterly Reports

The quarterly reports will include the following:

2.3.2.1 Raw data punched on computer cards in SAROAD format.

2.3.2.2 Hi-vol data

1. Tabulation of individual sample results (particulates, sulfates, nitrates, fluorides) for each station on a monthly basis.

2. Mean, standard deviation, maximum plus second high value of the above readings for each pollutant and station.

3. A fraction of all valid samples from each hi-vol sampler will be combined for each season quarter and analyzed as a single sample for trace elements. The quarterly report will tabulate the results of this trace element analysis.

2.3.2.3 SO_2 and NO_2 Bubbler Data

1. Tabulation of individual sample results for each station on a monthly basis.

2. The arithmetic mean and standard deviation for each station.

2.3.2.4 Continuous SO_2 Instrument Data

1. All individual hourly averages tabulated monthly.

2. High and second high 3-hour and 24-hour running averages noted for each month.

3. Arithmetic mean and standard deviation for each station (monthly and seasonal).

2.3.2.5 Continuous NO/NO_2 Instrument Data

1. All individual hourly averages tabulated monthly.

2. Arithmetic mean and standard deviation for each station (monthly and seasonal).

2.3.2.6 Cascade Impactor Data

1. Monthly tabulations of mass concentrations by particle size.

2. All valid samples from each cascade impactor sampler will be combined by fraction for each seasonal quarter and analyzed as a set for trace elements. That is, all first stages collected from a given impactor during a quarter will be

analyzed as a set. Similarly for the remaining stages (which collect particulate matter according to various size ranges). The results of this quarterly analysis will be included in this report.

2.3.2.7 Membrane Sampler Data

The membrane filters will be held for possible quantitative trace element analysis at a later date depending on the results of the semi-quantitative trace element analyses of the high-volume filters.

2.3.3 Annual Reports

The annual report will contain:

2.3.3.1 All summaries contained in quarterly reports plus appropriate annual means and standard deviations.

2.3.3.2 Chain of custody (sample and data handling procedures).

2.3.3.3 Quality assurance and laboratory analysis procedures for all parameters.

2.4 METEOROLOGY DATA ACQUISITION

Surface wind and upper atmosphere wind and temperature will be observed in the NGPRP study area. Table II-5 summarizes the type of observations to be made. Figure II-1 and Table II-2 give information on the specific sites and the data gathering activities performed there.

The entire meteorology network will be operational in early 1975, with data collection to last for a period of twelve months. This network has been designed with the intention of acquiring meteorological data necessary for mathematical pollutant diffusion models used to predict increases in ambient pollutant concentrations due to the presence of emission sources.

Several types of data will be recorded:

2.4.1 Surface wind speed and direction

Sixteen MRI surface weather stations will be located (Table II-2) at high-volume sampler sites to continuously record surface wind speed and direction. The data will be used to study air quality data anomalies by comparing air pollutant concentrations with local wind conditions.

The strip chart data will be digitized and ten minute averages of wind speed, and direction at all sites will be computed and stored on computer tape. Longer term averages and wind speed and direction distributions (wind roses) can then be computed.

TABLE II-5

NGPRP ATMOSPHERIC ASPECTS MONITORING NETWORK

METEOROLOGY	OBJECTIVE	SAMPLING FREQUENCY	ANALYSES
1. MRI Surface Weather Stations (16 stations)	Acquire surface wind speed and direction data. Compare data to pollution concentrations to study data anomalies.	Data recorded continuously.	10-minute and longer averages of wind speed and direction.
2. T-sondes (Temperature Soundings) (5 stations)	Determine temperature as a function of altitude. Will determine height of temperature inversions and (with pilot balloon data) joint wind frequency distributions needed for diffusion models.	Two observations per day, every other day for twelve months. Morning observation begins approximately ½ hour after sunrise; afternoon observation at approximately 2 p.m.	Plots of temperature vs. altitude.
3. Pilot Balloons (5 stations)	Determine wind speed and direction as a function of altitude.	Same as T-sondes.	Joint wind frequency distribution indicating probability of occurrence of a given wind.
4. Wind Towers, Bendix-Friez Aerovanes and strip chart recorders (5 stations)	Determine wind speed and direction at an altitude of 30 meters above ground level. Data will corroborate the extrapolation of morning and afternoon pilot balloon wind data to other times of the day.	Data recorded continuously.	1-hour averages of wind speed and direction.

2.4.2 Temperature Soundings

Balloons carrying small radio transmitters (T-sondes) will continuously broadcast the temperature as a radio signal during its flight. The signals are received at the ground and stored on magnetic tapes. These soundings will occur twice per day every other day for a twelve-month period at the following five locations: Colstrip and Glendive, Montana; Bowman and Stanton, North Dakota; and Gillette, Wyoming. Daily observations are to begin one-half hour after sunrise (approximate time minimum morning mixing height occurs) and again at approximately 2 p.m. (approximate time maximum afternoon mixing height occurs). Measurements of the vertical temperature profile will extend from ground level to an altitude of 6,000 feet above ground level (AGL). The T-sondes will be used in conjunction with pilot balloons. (See Section 2.4.3)

This temperature profile data will give information on mixing layer heights (Regional Profile Section 1.3); when compared with pilot balloon wind data it will permit the categorization of joint frequency distributions of wind speed and direction (Section 2.4.3) according to atmospheric stability classes (Regional Profile Section 1.3).

2.4.3 Upper Wind Data (Using Pilot Balloons)

Pilot balloons and single theodolites will be used to make observations of wind speed and direction from ground level to 6,000 feet AGL. The balloons are tracked with the theodolite, an optical device, which measures the balloon's angular coordinates (elevation and azimuth). Changes in these coordinates are related to wind speed and direction. The pilot balloon - T-sonde package will be flown at 5 sites, twice per day every other day for 12 months.

The major objective of the pilot balloon observations is to derive a joint frequency distribution of wind speed and direction, as shown in Figure II-4. Each entry in the matrix gives the probability (or percent of time) that during a given month (or season, or year) the wind was from a given direction, with a speed within a given range and the atmosphere described by a given stability class.

2.4.4 Wind Tower Data

At the above five locations, existing towers will be equipped with Bendix-Friez Aerovanes at an elevation of 30 meters. The Aerovanes will continuously record wind speed and direction during a twelve-month period. The resulting data will corroborate the extrapolation of morning and afternoon wind data (2 observations/day) to other times of the day. The pilot balloon observations will be made in the vicinity of these wind towers.

All strip chart data will be reduced and 1-hour speed and direction averages tabulated.

FIGURE II-4

MONTH: ________ YEAR: _______ STATION: ______________________ ALTITUDE: ____________________
(Or Season, Annual)
(Above Grd Level)

NORMALIZED FREQUENCY DISTRIBUTION+

DIRECTION	SPEED (METER/SEC)							
	0-3	4-6	7-10	11-16	17-21	GREATER THAN 21	AVE* SPEED	TOTAL
N								
NNE								
NE								
ENE								
E								
ESE								
SE								
SSE								
S								
SSW								
SW								
WSW								
W								
WNW								
NW								
NNW								
AVG SPEED*								
TOTAL								

NOTES:

+ Suggested reference for computing normalized frequency distribution is the STAR Program, of the National Climatic Center of the National Oceanic and Atmospheric Administration, U. S. Department of Commerce.

* Noted Row and Column indicate average speed in meters/sec averaged over all directions, and for given direction, respectively.

** Similar tables required for B, C, D, E, F stability classes and also one indicating the total normalized frequency distribution of all observations regardless of stability class, as per STAR PROGRAM.

RELATIVE FREQUENCY OF OCCURRENCE OF A STABILITY = ** ____________________

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH A STABILITY = ________________________

2.4.5 Data Summary Reports

Summaries of data will be distributed on a seasonal and annual basis. The actual data, in tape and computer card format, will be held at the Denver Regional EPA office and will be available to those interested on request.

2.4.5.1 Monthly Data Reports

The following will be available on a monthly basis:

1. Surface Wind Data

A computer tape storing 10-minute averages of surface wind speed and direction resulting from raw data recorded at the sixteen stations during a given calendar month.

2. Vertical Temperature Profile Data

All temperature profile data for all station soundings made during each calendar month will be stored on computer magnetic tape.

Also, plots of the temperature profile for all soundings will be included, as illustrated in Figure II-5. The profiles will flag those "significant altitudes" where the temperature curve exhibits sharp changes.

3. Wind Tower Data

Tabulations of hourly averages of wind speed and direction covering a period of one calendar month will be available for all five sites.

4. Pilot Balloon Data

Microfilm and paper copy of plots of wind speed versus altitude and wind direction versus altitude will be made from each observation made during a calendar month at the five sites.

For all five stations, a monthly joint frequency distribution as per Figure II-4 for each of six atmospheric stability classes will be computed. Paper copy and computer card output will be available.

2.4.5.2 Quarterly Reports

Seasonal joint wind frequency distribution will be categorized according to six stability classes, STATION: ____________ DATE: __________ TIME: ________

SOUNDING ID NUMBER: ____________

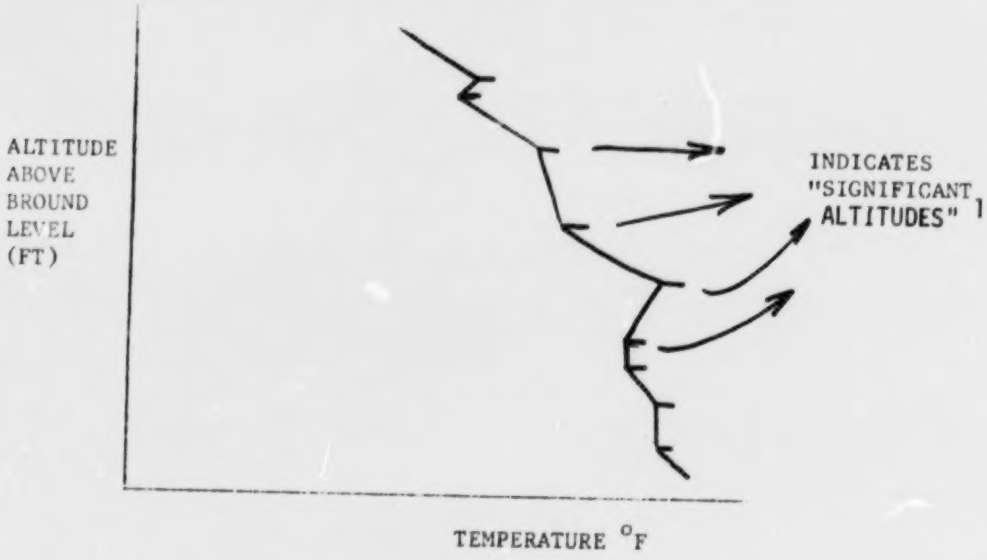


FIGURE II-5

1. Section 4.5.1.2

as in Figure II-4. Paper copy and computer card output will be available.

2.4.5.3 Annual Reports

An annual, seasonal, monthly joint wind frequency distribution for each of the five stations will be available on computer cards, paper copy, or computer magnetic tape.

SECTION III

CONSTRAINTS

3.1 FEDERAL CLEAN AIR ACT, AS AMENDED IN 1970

In December, 1970, Congress enacted legislation empowering the Environmental Protection Agency to establish national ambient air quality standards (NAAQS) (Section 109); standards of performance for new stationary sources (NSPS) (Section 111); and national emission standards for hazardous air pollutants (NESHAPS) (Section 112). A June 11, 1973, U. S. Supreme Court decision, in effect, ordered the EPA to insure that all State Implementation Plans (SIP) provided for the prevention of significant deterioration of present air quality levels. Prior to that decision and following a U. S. Court of Appeals decision, SIP's were reviewed, and that portion of the plan pertaining to the prevention of significant deterioration was disapproved for all plans on November 9, 1972. Another court order, that resulting from a decision in the case of Natural Resources Defense Council et al, vs EPA on January 31, 1973, directed EPA to promulgate regulations designed to maintain the NAAQS after 1975. These regulations will be designed to control emissions relating to shopping centers, airports, etc. States must also submit 10 year maintenance plans which will protect the NAAQS through 1985.

The previously mentioned areas of EPA responsibility would appear to identify all of the regulatory constraints that exist within the jurisdictional framework of the EPA. A detailed discussion of each of these five areas follows.

3.1.1 National Ambient Air Quality Standards (NAAQS)

Ambient air quality standards for suspended particulate matter, sulfur oxides, nitrogen oxides, photochemical oxidants, carbon monoxide, and hydrocarbons were promulgated by EPA on April 30, 1971. Table III-1 lists these standards. It is the responsibility of the state air pollution control agencies to insure that these standards are attained and maintained. If the states will not or cannot perform this task, the EPA must take the required appropriate action. Two kinds of NAAQS were promulgated by the EPA. Primary standards are health related and, in most cases, must be achieved by July 1975. Secondary standards are welfare; i.e., material, vegetation, visibility, etc. related and must be achieved as expeditiously as possible. In rural areas this may mean July 1975, whereas in urban areas it may even mean well beyond July 1977.

3.1.2 New Source Performance Standards (NSPS)

Section 111 of the Act mandated that the EPA from time to time establish standards of performance for a category of sources whose emissions the Administrator feels may cause or contribute significantly

TABLE III-1

NATIONAL AMBIENT AIR QUALITY STANDARDS

POLLUTANT	PRIMARY STANDARD	SECONDARY STANDARD
1. Sulfur Oxides	80 ug/m^3 (0.03 ppm) annual arith. mean 365 ug/m^3 (0.14 ppm) max 24 hr. conc. not to be exceeded more than once a year.	1300 ug/m^3 (0.5 ppm) max 3 hr. conc. not to be exceeded more than once a year.
2. Particulate Matter	75 ug/m^3 annual geom. mean 260 ug/m^3 max 24 hr. conc. not to be exceeded more than once a year.	60 ug/m^3 annual geom. mean *, 150 ug/m^3 max 24 hr. conc. not to be exceeded more than once a year
3. Carbon Monixide	10,000 ug/m^3 (9ppm) max 8 hr. conc. not to be exceeded more than once a year	Same as primary
	40,000 ug/m^3 (35 ppm) max 1 hr. conc. not to be exceeded more than once a year	Same as primary
4. Photo Chemical Oxidants (corrected for NO_2 and SO_2 interference	160 ug/m^3 (0.08 ppm) max 1 hr. conc. not to be exceeded more than once a year.	Same as primary
5. Hydrocarbons (corrected for CH_4)	160 ug/m^3 (0.24 ppm) max 3 hr. conc. (6 to 9 a.m.) not to be exceeded more than once a year.	Same as primary
6. Nitrogen Oxides (as Nitrogen Dioxide)	100 ug/m^3 (0.05 ppm) annual arith. mean	Same as primary

* To be used as guide in assessing State Implementation Plans

to endangerment of the public health or welfare. This "standard" must reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated". On December 23, 1971, EPA promulgated standards of performance for fossil fuel-fired steam generators. The heat input rating, i.e., the heating value of the fuel introduced to the unit, must be greater than 250 million BTU per hour in order for the regulation to apply. This is equivalent to about a 25 megawatt plant. Any plants under construction or modification to existing plants after August 17, 1971, must conform to the limits shown below in Table III-2.

TABLE III-2

NSPS FOR STEAM GENERATORS

	Allowable Emissions		
	Fuel-Fired		
	Coal	Oil	Gas
Particulate, #/10^6 BTU	0.10	0.10	0.10
Particulate, opacity	20%	20%	20%
Sulfur Dioxide, #/10^6 BTU	1.20	0.80	--
Nitrogen Oxides, #/10^6 BTU	0.70	0.30	0.20

To put these regulations into perspective, we should look at what requirements would be imposed upon the "average" new power plant. Let us assume a 1,000 megawatt plant burning coal with an ash content of 10 percent, sulfur content of 1.0 percent, and a heating value of 9,000 BTU per pound. This plant would have to take measures to insure about 99 percent particulate matter emission control, about 46 percent SO_2 emission control, and about 30 percent NO_x emission control.

3.1.3 National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Emission standards have been and are to be promulgated for any air pollutant to which no ambient air quality standard is applicable and which may cause or contribute to an increase in mortality or an increase in serious irreversible or incapacitating reversible illness. Section 112 of the Act empowers the EPA Administrator to make such determinations from time to time. At the present time, standards have been promulgated (April 6, 1973, Federal Register) for asbestos, beryllium, and mercury. None of these standards would appear to apply to the anticipated fuel conversion facilities. The mercury limitation of 2,300 grams per day only applies to mercury cell chlor alkali plants and mercury ore processing facilities. The limitation is designed to limit ambient concentrations of mercury to below one microgram per cubic meter.

The EPA is conducting on-going research to establish criteria and the need for inclusion of a number of materials as potential candidates for the hazardous pollutants list. Many of the trace elements that may be emitted in power plant stack effluent gases are being studied. Much work to date has been performed on cadmium, arsenic, and fluorine. Conclusion by the EPA that any material is hazardous, and the subsequent promulgation of an emission standard, will prove to be a factor which must be considered in designing the air pollution control system on any future development. Hazardous pollutant emission standards apply to both new and existing sources.

3.1.4 Prevention of Significant Air Quality Deterioration

In response to a court suit, the EPA has proposed regulations (July 16, 1973, Federal Register) which attempt to define significant deterioration and implement control procedures designed to prevent the occurrence of a significant deterioration of existing air quality levels. The final form of the regulations is still unresolved at the time of this writing. Much testimony was heard during the public hearings held around the country, but apparently there was not much progress in terms of quantitative resolution. The original EPA thinking on how to prevent significant deterioration centered upon four alternatives.

The first plan would define incremental air quality levels as a measurement of deterioration. The second approach would use incremental emission density as a yardstick. A third plan would require state and local agencies to decide on a case-by-case basis whether or not a proposed new source would constitute a significant deterioration of air quality. In this approach, it is conceivable that the existing air quality could be allowed to be degraded up to the NAAQS. The fourth approach would combine the air quality increment idea with a zoning practice in order to define allowable levels of new pollution. None of these approaches is without drawbacks, and an all-out effort is being conducted in order to judicially handle the significant deterioration situation. Present EPA thinking would combine a couple of the previously mentioned alternatives. It is thought that a State would be required to identify three types of geographical zones. Zone 1 would remain with "pristine type" air quality such that only a small increase in air quality levels would be allowed. Zone 2 areas would be allowed a somewhat larger increase in air quality levels. Zone 3 would represent areas in the State that air quality could be degraded up to the secondary standard. In any event, the final outcome will insure that air quality levels will get no worse than the secondary NAAQS. Tables III-3 and III-4 illustrate the present EPA thinking on allowable air quality level increases in the three zones. Table III-5 illustrates the comparison between the present air quality levels in the NGP and the NAAQS. Table III-6 provides further insight to the history of the significant deterioration issue.

The final definition and regulations imposed to prevent significant deterioration may well be the single most confining environmental constraint to mineral resource development in the NGP. For example, the final

TABLE III-3

INCREASES IN CONCENTRATION ALLOWED UNDER MODIFIED AREA CLASSIFICATION PLAN

	TSP		SO_2		
	Annual	24 Hr.	Annual	24 Hr.	3 Hr.
Zone I	5	10	2	5	25
Zone II	10	30	15	100	700
Ambient Air Quality Standard	75*	150	80*	365*	1300

* Primary Standard

TABLE III-4

MODIFIED AREA CLASSIFICATION PLAN

1. THREE AIR QUALITY ZONES

   ZONE I - NO CHANGE IN AIR QUALITY DESIRED

   ZONE II - MODEST CHANGE IN AIR QUALITY DESIRED

   ZONE III - CONCENTRATIONS UP TO SECONDARY STANDARDS PERMITTED

2. EXCEPTION POSSIBLE

   a) MAY VIOLATE STANDARD OF ZONE I OR ZONE II IF FOR SUFFICIENT CAUSE.

   b) IF WITHIN 25 MILES OF STATE BOUNDARY, THEN ADJACENT STATE MUST BE NOTIFIED.

3. NINETEEN SOURCE CATEGORIES MUST CONFORM TO BEST AVAILABLE CONTROL TECHNOLOGY

4. EXEMPTION

   a) SOURCE SHIFTING FROM CLEAN TO DIRTY FUEL DUE TO SHORT SUPPLY
   b) SOURCE EXISTING FOR SHORT TIME

TABLE III-5

SELECTED COMPARISON OF PRESENT AIR QUALITY WITH SECONDARY NAAQS

Standards

Particulate - 60 ug/m^3 Annual geometric mean
150 ug/m^3 24 hour
Sulfur Oxides - 260 ug/m^3 34 hour

Location	Year	Particulate, ug/m^3 24 hour	Particulate, ug/m^3 Annual	Sulfur Oxides, ug/m^3 Annual
MONTANA				
No data available				
NORTH DAKOTA				
Bismarck	1972	213	87	---
Dickinson	1972	105	42	---
Minot	1972	420	60	---
Mandan	1972	112	42	---
Lake Darling	1972	63	19	---
SOUTH DAKOTA				
Black Hills	1972	66	16	4
Rapid City	1972	253	71	---
WYOMING				
Casper	1972	166	61	2
Gillette	1972	190	73	---

TABLE III-6

NO SIGNIFICANT DETERIORATION

A. MAY 24, 1972 - SUIT FILED

B. MAY 30, 1972 - DISTRICT COURT OF COLUMBIA DECISION

C. NOV. 1, 1972 - U. S. COURT OF APPEALS FOR DISTRICT OF COLUMBIA DECISION

D. NOV. 9, 1972 - STATE PLANS DISAPPROVED

E. JUNE 11, 1973 - SUPREME COURT SPLIT DECISION

F. JULY 18, 1973 - EPA PROPOSED REGULATIONS

G. AUGUST 26, 1974 - EPA REPROPOSED REGULATIONS

H. DEC. 5, 1974 - EPA PROMULGATED REGULATIONS

regulations may restrict the number or size of power plants constructed in a region.

3.1.5 Maintenance of NAAQS

The anticipated wide scale of power development in the NGP will bring with it the attendant urban growth activity. This growth activity will bring about potential increased pollutant levels. As an example, an average large power generating plant with associated coal mine would support about 400 employees. Cities will grow because of the need to provide goods and services for these employees and their families. Due to the large number of plants being planned for, the creation of new cities, as well as the growth of existing cities, is a real likelihood. This development could have an impact upon the maintenance of the NAAQS. Thus, in response to a court order, the EPA proposed and later promulgated (February, 1974, Federal Register) procedures designed to provide for the maintenance of NAAQS once they are achieved. Under these procedures, a State must prepare a 10-year maintenance plan which will insure that once the air quality standards are attained they are maintained. As part of this procedure, a State must consider what pollutant emissions may reasonably be expected due to the construction of facilities and how those emissions will be controlled. The state will do this as part of its new source review procedure. Much of the environmental impact to be felt in a community due to the construction of a new facility could be related to mobile source pollutants. Tables III-7, 8 and 9 provide the promulgated source category regulations along with the time schedule for development of the 10-year maintenance plans.

3.2 STATE AIR POLLUTION REGULATIONS

Prior to and subsequent to passage of the Federal Clean Air Act of 1970, states have adopted regulations for the control of air pollution. These regulations take two forms: 1) air quality standards, and 2) emission regulations. As a requirement of the Federal Clean Air Act of 1970, states were to prescribe measures designed to attain and maintain air quality levels equal to or better than the NAAQS.

Different states promulgated different regulations, dependent upon their needs and/or desires. Tables III-10 through III-14 list the air quality standards adopted by the five states in the NGP. As can be seen, some of the states have regulations pertaining to pollutants besides the six criteria pollutants. In fact, the sulfate and fluoride air quality standards adopted by Montana and North Dakota may prove to be severe contraints upon energy development. Any mineral resource development in the NGP must be able to insure that it will not cause the violation of any of these air quality standards.

Emission regulations have been adopted by the various states. Compliance with these regulations is estimated by the state to attain at least the NAAQS. The anticipated power development in the NGP will have

TABLE III-7

EPA PROMULGATED INDIRECT SOURCE REVIEW REGULATION

Effective Date: 7/1/74
Applicable Date: 7/1/75

Within SMSA

a. New parking facility with associated parking > 1000 cars

b. Modified parking facility which increases parking capacity > 500 cars

c. Any new highway section with A.D.T.V. > 20,000 vehicles within 10 years of construction

d. Any modified highway section with increased A.D.T.V. 10,000 vehicles within 10 years of modification.

Outside SMSA

a. New parking facility with associated parking > 2000 cars

b. Modified parking facility which increases parking capacity > 1000 cars

Airports

a. New airport with > 50,000 operations per year by regularly scheduled air carriers, or > 1,600,000 passengers per year

b. Modified airport with increase equivalent to (a)

TABLE III-8

10-YEAR MAINTENANCE PLAN

MARCH 18, 1974	STATE SUBMISSION OF IDENTIFICATION OF AQMA'S
AUGUST 16, 1974	EPA PUBLICATION OF LIST OF AQMA'S
JUNE 18, 1975	STATE SUBMISSION OF: A. IMPACT ON AIR QUALITY OF PROJECTED GROWTH IN AQMA'S B. WHERE NEEDED, A PLAN TO PREVENT ANY NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) FROM BEING EXCEEDED OVER THE 10-YEAR PERIOD FROM THE DATE OF PLAN SUBMITTAL.

TABLE III-9

MAINTENANCE PLANNING

1. DESIGNATE MAINTENANCE AREAS
   - A. LOCATE POSSIBLE PROBLEM AREAS
     1. PRESENT POLLUTION SOURCES
     2. PRESENT SMSA'S
     3. MAJOR RECREATIONAL AREAS
   - B. SELECT AREAS: POTENTIAL TO EXCEED STANDARDS
     1. GROWTH FACTORS
     2. EXISTING PLANNING AREAS
     3. COUNTY AND TOWNSHIP BOUNDARIES
2. DEVELOP MAINTENANCE STRATEGY FOR EACH AREA
   - A. PROJECT ALLOWABLE POLLUTION INCREASE
     1. PRESENT AIR QUALITY
     2. PRESENT EMISSIONS
     3. AIR QUALITY STANDARDS
   - B. METHODS TO LIMIT EMISSION INCREASE
     1. LAND USE REGULATIONS
     2. EMISSION LIMITATION REGULATIONS
     3. EMISSION DENSITY REGULATIONS
     4. OTHER
   - C. CHECK FOR LEGAL AUTHORITY
   - D. PASS REGULATIONS

TABLE III-11

Ambient Air Quality Standards - Nebraska

POLLUTANT	STANDARD, ug/m^3				
	Annual	24-hour*	8-hour*	3-hour**	1-hour*
Particulate, primary	75	260	-	-	-
secondary	60	150	-	-	-
SO$_x$, primary	80	365	-	-	-
secondary	-	-	-	1300	-
NO$_x$	100	-	-	-	-
CO	-	-	10,000	-	40,000
Oxidants	-	-	-	-	160
Hc	-	-	-	160**	-

* Not to be exceeded more than once per year

** Between 6 a.m. and 9 a.m.

TABLE III-10

Ambient Air Quality Standards - Montana

POLLUTANT	STANDARD				
	Annual	Month	24-hour	1/2 hour	1 hour
Particulate, ug/m^3	75 geometric mean (G.M.)	-	200 1% of time *	-	-
SO_2, ppm	0.02 arithmetic mean (A.M.)	-	0.10 1%/3 months*	-	0.25 once/4 days *
, sulfation - mg $SO_3/100\ cm^2/day$	0.25	0.50	-	-	-
, sulfate - ug/m^3	4	-	- 12-1% of time	-	-
H_2SO_4, ug/m^3	4	-	- 12-1% of time	-	30 1% of time*
H_2S, ppm	-	-	-	0.03 twice/5 days* 0.05 twice/year *	-
Pb, ug/m^3	-	5.0	-	-	-
Be, ug/m^3	-	0.01	-	-	-
Fl, total as HF - ppb	-	-	1	-	-
, as F in forage, ppm w	35	-	-	-	-
, gaseous - ug/cm^2	-	0.3	-	-	-

* not to be exceeded more than

TABLE III-12
Ambient Air Quality Standards - North Dakota

POLLUTANT	STANDARD						
	Annual	Month	24-hour	8-hour	3-hour	1 hour	1/2 hour
Particulate, ug/m^3	60 G.M.	-	150 **	-	-	-	-
, COH/1000 lineal feet	0.4	-	-	-	-	-	-
SO$_2$, ug/m^3	60 A.M.	-	260 **	-	-	715 **	-
, sulfation - mg SO$_3$/100 cm^2 day	0.25	0.50	-	-	-	-	-
, sulfate - ug/m^3	4	-	- 12-1% of time*	-	-	-	-
CO, mg/m^3	-	-	-	10 **	-	40 **	-
NO$_x$, ug/m^3	100	-	-	-	-	200 1% /3 months*	-
HC, ug/m^3	-	-	-	-	160 **		-
Oxidants, ug/m^3	-	-	-	-	-	160 **	-
H$_2$SO$_4$, ug/m^3	4	-	12 1% of time*	-	-	30 1% of time *	-
H$_2$S, ug/m^3	-	-	-	-	-	-	*45 twice/ 5 days *75 twice/ yr

* Not to be exceeded more than
** Not to be exceeded more than once per year

TABLE III-13
Ambient Air Quality Standards - South Dakota

POLLUTANT	STANDARD						
	Annual	Month	24-hour	8-hour	3-hour	1-hour	1/2 hour
Particulate, ug/m^3	60 G.M.	-	150 *	-	-	-	-
, COH/1000 feet	0.2	-	-	-	-	-	-
SO_2, ug/m^3	60 A.M.	-	260 *	-	-	-	-
CO, mg/m^3	-	-	-	10 *	-	15 *	-
NO_x, ug/m^3	100 A.M.	-	250 *	-	-	-	-
HC, ug/m^3	-	-	-	-	125 *	-	-
Oxidants, ug/m^3	-	-	-	-	-	125 *	-

* Not to be exceeded more than once per year

TABLE III-14

Ambient Air Quality Standards - Wyoming

POLLUTANT	STANDARD						
	Annual	Month	24-hour	8-hour	3-hour	1-hour	1/2 hour
Particulate, ug/m^3	60 G.M.	-	150 **	-	-	-	-
, COH/1000 feet	0.4	-	-	-	-	-	-
SO_2, ug/m^3	60	-	260 **	-	1,300 **	-	-
, sulfation mg SO_3/100 cm^2/day	0.25	0.50	-	-	-	-	-
CO, mg/m^3	-	-	-	10 **	-	40 **	-
NO_x, ug/m^3	100 A.M.	-	-	-	-	-	-
HC, ug/m^3	-	-	-	-	160 **	-	-
Oxidants, ug/m^3	-	-	-	-	-	160 **	-
HF, total, ppb	-	-	1	-	-	-	-
HF, forage - ppmw	25	-	-	-	-	-	-
HF, gaseous ÷ ug/cm^2	-	0.3	-	-	-	-	-
H_2S, ug/m^3	-	-	-	-	-	-	*40 twice/5 days *70 twice/5 days

* Not to be exceeded more than

** Not to be exceeded more than once per year to comply with the emission regulations in Tables III-15 through III-19 for the respective states. Compliance with these regulations is in addition to any Federal emission regulations that may be applicable.

Any mineral resource development in the NGP will have to comply with applicable local regulations. Of the states in the NGP, only Montana has a local agency with adopted emission regulations of their own. The Billings agency regulations are no more stringent than the state regulations. Also, the state has retained jurisdiction over the major sources of pollution, such as the refineries and power plants. Therefore, unless local agencies are formed in the future, compliance with state and Federal regulations fully covers the requirements placed upon a source.

3.3 NATIONAL ENVIRONMENTAL POLICY ACT

Implementation of the National Environmental Policy Act (NEPA) can be a constraint to be considered in air resource management to the extent that it requires changes in the planning process to fully consider environmental values. These changes include the use of a systematic, interdisciplinary approach, use of ecological information, appropriate consideration of unquantified environmental values, and preparation of environmental impact statements. The court decisions on the environmental impact statement requirement of NEPA make it clear that Federal agencies must fully disclose potential environmental effects, consider all reasonable alternatives, and carefully balance economic, technical, social and environmental factors in reaching a decision. While Federal agencies have taken many steps to revise their planning processes in response to NEPA, further changes will be necessary as NEPA is interpreted administratively and judicially.

In the short term, NEPA will act as an administrative constraint until agencies have adjusted to its requirements. In both the short and long term, NEPA will act as a constraint as Federal actions must be modified in response to public review and comments on potential environmental impacts.

3.4 STATIONARY SOURCE SITING

Due to the magnitude of the anticipated resource development in the NGP, care must be exercised by industry in choosing their sites for operations. The potential cumulative effect of several power plants in a given locale must be considered. It is difficult to make sound quantitative estimates of the combined effects of the operations of several coal fired power generating plants, because of the number of variables that enter the situation. Data including emission release rates, stack parameters, terrain characteristics, atmospheric conditions, site locations, etc. would be needed for specific plant sites and for the surrounding region before any solid judgment could be made as to the effects of one plant or a combination of plants. These factors will, in effect, establish the maximum size plant that can be tolerated in a given location from an environmental viewpoint.

TABLE III-15

Emission Regulations - Montana

A. Fuel Combustion - Particulate Matter

10^6 BTU/hr. (1) Fuel Heat Input	# Particulate/10^6 BTU (2) Existing Source	New Source
10	0.6	0.6
100	0.4	0.35
1,000	0.28	0.20
10,000	0.19	0.12

B. Fuel Combustion - Sulfur Compounds

Effective Date	Pollutant	Allowable Emissions
July 1, 1972	SO_2	1.0 #S/10^6 BTU
July 1, 1971	H_2S	50 grains/100 ft^3

C. Visible Emissions

Existing Source	40 percent opacity
New Source (2)	20 percent opacity

(1) Interpolate between values

(2) After November 23, 1968

TABLE III-16

Emission Regulations - Nebraska

A. Fuel Combustion - Particulate Matter

10^6 BTU/hr. (1) Fuel Heat Input	# Particulate/10^6 BTU
$\leq$ 10	0.60
$\geq$ 3800	0.15

B. Fuel Combustion - SO_2

Allowable = 2.5 # SO_2 / 10^6 BTU

C. Visible Emissions

Existing sources (2) 20 percent opacity

---

(1) Interpolate by equation $A = \frac{1.026}{I^{0.233}}$

where A = allowable emissions, #/10^6 BTU
I = total heat input 10^6 BTU/hr

(2) Effective compliance date is August 24, 1974

TABLE III-17

Emission Regulations - North Dakota

A. Fuel Combustion - Particulate Matter

10^6 BTU/hr (1) Fuel Heat Input	# Particulate/10^6 BTU (2) Existing Source	New Source
10	0.8	0.6
100	0.8	0.443
1,000	0.8	0.328
10,000	0.8	0.242
100,000	0.8	0.180

B. Fuel Combustion - SO_2

Allowable = 3.0 #$SO_2/10^6$ BTU

C. Visible Emissions

Existing Source	40 percent opacity
New Source (2)	20 percent opacity

(1) Interpolate between values

(2) After January 24, 1972

TABLE III-18

Emission Regulations - South Dakota

A. Fuel Combustion - Particulate Matter

Allowable Emissions = 0.30 $\#/10^6$ BTU

B. Fuel Combustion - SO_2

Allowable emissions = 3.0 # SO_2 / 10^6 BTU

C. Fuel Combustion - NO_x

Fuel Fired	Allowable Emissions, $\#/10^6$ BTU
Gas	0.2
Oil	0.3

D. Visible Emissions

Allowable = 20 percent opacity

TABLE III-19

Emission Standards - Wyoming

A. Fuel Combustion - Particulate Matter

10^6 BTU/hr. (1) Fuel Heat Input	# Particulate/10^6 BTU Existing Source	(2) New Source
10	0.6	0.10
10,000	0.18	0.10

B. Fuel Combustion - NO_x

Fuel Fired	# NO_x / 10^6 BTU Existing Source	(2) New Source
Gas	0.23	0.2
Oil	0.46	0.3

C. Visible Emissions

Existing Source	40 percent opacity
New Source (2)	20 percent opacity

---

(1) Interpolate between values

(2) After February 22, 1972

There have been attempts made to estimate the possible environmental impact of power generating stations. EPA has (July 16, 1973, Federal Register) estimated that a 1,000 to 1,500 megawatt plant complying with the SO_2 NSPS would contribute 50 to 200 micrograms per cubic meter to the 24 hours SO_2 ambient air average. The variation is a function of the terrain and other factors previously mentioned. The concentration could be expected to occur over as much as a 700 square mile area, depending, of course, upon meteorological conditions. Specific point source modeling was performed for eight power plants either in the construction or construction planning stage in the NGP. Results of the modeling effort are discussed in Section V of this report.

Estimates of the cumulative effects of several power plants in the same proximity are subject to the same considerations mentioned earlier. As part of the Southwest Energy Study, NOAA estimated that if "average" size plants were located more than 100 km apart, there would be no cumulative effects of their emissions upon air quality levels. When plants are located within 25 km of each other, it was estimated that there would be additive effects both on short-term and long-term concentrations. The Atmospheric Aspects Work Group's final report to be written and published in 1975 will contain results of a regional modeling effort. This effort will identify the effect of a group of power plants upon a region or air shed somewhat removed from the power plant sites. For a more thorough discussion of this regional effort, see Section V of this report.

Another siting factor that must be considered is the effect of the cooling tower plume, if applicable, and the stack plume, if existent, upon visibility and vegetation. The additional occurrence of fog due to cooling towers of up to 100 hours per year in some locations is documented.[1] Also, hazardous driving conditions due to the cooling tower plume may exist if a plant is constructed too close to a highway or vice versa. Fatal accidents have occurred because of a cooling tower plume obscuring visibility on a major highway. The reclamation efforts may be significantly influenced by the impact of the cooling tower salts and the stack emissions because of the susceptibility of young plants.

Atmospheric conditions in the NGP generally represent situations resulting in good dispersion. A very low frequency of stagnation conditions exist. Fronts moving in from the northwest and air masses coming up from the Gulf tend to result in a well mixed atmosphere. Also, the relative absence of mountainous valleys and severely contrasting terrain, along with higher than average wind velocity, should preclude the existence of trapping and impaction of plumes as is experienced by some of the power plants in the southwest. Data are being accumulated with the NGP monitoring network to substantiate or disprove this observation.

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1. Southwest Energy Study, Appendix E, Report of the Meteorology Work Group.

3.5 LAND USE LIMITATIONS

States in the NGP have zoning restrictions in urban areas as to where a fuel conversion facility or resource development activity can be located. The zoning regulations are classified in the terms of typical residential, commercial, industrial, etc. categories. This constraint will serve merely to insure that a power plant, for instance, is not located too near to a residential area. For example, by law, counties have the authority in Montana to set county-wide zoning restrictions upon structural development. The authority to establish zoning restrictions upon mining or any other extractive mineral development is prohibited.

The Montana Utility Siting Act of 1973 may serve as a constraint upon resource development in the NGP. The purpose of the Act is stated to be to "ensure that the location, construction and operation of power and energy conversion facilities will produce minimal adverse effects on the environment and upon the citizens of this State..." A "certificate of environmental compatability and public need", issued by the Board of Natural Resources and Conservation, is required before any major energy related facility may be constructed. Facilities such as fossil fuel fired steam generating plants, coal gasification plants, coal liquefaction plants, transmission lines, and petroleum pipelines, must obtain a certificate before commencing construction. Application must be submitted two years prior to commencement of construction. Within 600 days of such application, the Department of Natural Resources and Conservation shall report to the Board on their findings of the anticipated environmental impact of the proposed project. Any facilities construction begun after January 1, 1973, is subject to the stipulations of the Act. The Act should have a positive force in planning for the development of the mineral resources in Montana, while maintaining the present high quality environment that exists.

3.6 NATIONAL ENERGY EMERGENCY ACTS

In order to lessen the impact of the current energy shortages, Congress has responded with energy emergency legislation. On November 19, 1973, a bill called the National Energy Emergency Act (H. R. 11450) was introduced into the House. The House and Senate versions are very similar. A compromise bill was passed by both the House and Senate but vetoed by President Nixon. The veto was not overridden. Key points of the Act included: 1) mandatory energy conservation programs will be established; 2) domestic oil production will be increased; 3) stationary sources must burn coal if they have the capability; 4) "dirty areas" of the United States will get priority on clean fuels; 5) primary health standards will be observed "as nearly as possible" and 6) crude oil price rollbacks. It was stated by the Administration that the last item proved to be the major factor in the President's decision to veto the bill.

While on a nationwide basis, the mandatory conservation program designed at reducing energy consumption by 25 percent may lessen the need for the anticipated NGP development, a balancing factor may be the increased demand for low sulfur coal by industrial and utility facilities. Thus, a situation that could result is that fewer fuel conversion facilities would be constructed in the NGP, but much more mining activity would take place in order to ship the low sulfur coal to the East. The other possibility that exists is a tremendous increased demand for coal gasification or coal liquefaction plants may result. This would bring with it the attendant increased construction of gas pipelines in the NGP.

A forced conversion of all present facilities burning petroleum products to coal operation will bring about a degradation of existing air quality levels. Conversion of present facilities, coupled with the proposed regulations on significant deterioration of air quality (July 16, 1973, Federal Register), could constrain future development or at least cause changes in plant site locations on a nation-wide basis. Facilities presently burning coal that were contemplating a switch to oil or gas as part of a compliance schedule to meet an applicable emission regulation may receive a variance from that regulation until no later than July 1, 1977. The source must also show that it has entered into a contractual agreement to obtain a continuous emission reduction system. There are attempts in the Congress and the Administration at the present time to amend the Clean Air Act to modify some of the compliance dates and permanent control requirements.

3.7 "OTHER" ENVIRONMENTAL EFFECTS

Perhaps in the future, as more data are gathered, more will be known about the effects of air pollution sources upon potentially serious environmental impacts, such as: 1) reduction in solar radiation reaching the ground; 2) increased atmospheric loading of sulfates and nitrates; 3) acidification of rain; 4) increased global CO_2 concentrations, and other lesser studied atmospheric chemical and physical reactions. Any one of the above situations could prove to have more serious long-term detrimental effects than any pollutants or effects which have been identified as harmful at the present time. The NGP program has identified these aspects as research needs and has proposed funding of some related work. Provisions for long-term monitoring programs in order to accumulate data for trend analyses have been proposed.

The broader scope of all extractive mineral resource activity should be studied. In view of the uranium reserves in the NGP, careful attention must be paid to nuclear power generating plant development or uranium enrichment activity. Potentially harmful radioactive wastes must be controlled. Cooling tower plumes from nuclear plants would be subject to the same comments made earlier regarding fossil fuel fired plant cooling towers.

3.8. AIR POLLUTION CONTROL TECHNOLOGY

Development of reliable control equipment must proceed at a much faster rate than it has in the past, if the anticipated increase in power development in the NGP becomes a reality. Otherwise significant environmental degradation may occur. Improved combustion techniques must also be developed for the control of some pollutants, such as NO_x. The status of reliable commercial equipment is the subject of intense debate among utility owners, control equipment manufacturers, and governmental pollution control agencies. Much of the debate centers upon the reliability of SO_2 scrubbers on commercial installations. The practical resolution of this debate in the form of installed equipment should prove whether or not the availability of adequate control equipment is a constraint to future resource development.

Control of particulate matter from power plants has been achieved primarily through installation of electrostatic precipitators with a few installations of wet scrubbers and fabric filters in existence. Problems have surfaced recently with electrostatic precipitator collection efficiency when operating on low sulfur coal fly ash. The apparent reason for the decreased collection efficiency is related to the high particle resistivity. The electrostatic charge does not leak off, with the subsequent formation of a high electric field in the dust layer on the plate. This, in turn, causes excessive sparking and back corona. The voltage, and hence corona current, must be reduced when this occurs, which, in turn, decreases collection efficiency. Attempts to solve the resistivity problem have centered upon stack gas conditioning with SO_3, installation of hot-side precipitators, design of enlarged cold-side precipitators, and cooling stack gases to below 250° F. Electrostatic precipitators, of course, have only a minimal effect upon the SO_2 emissions leaving in the stack gases. Some sulfur in the form of SO_2 will adhere to the fly ash thus being collected, but this would represent a maximum of 15 percent of the input sulfur.[2] Precipitators can achieve better than 99 percent by weight particulate control.

Wet scrubbers have been introduced as a means of particulate and SO_2 control. Although there are several pilot plant and commercial prototype installations throughout the country, only a few are enjoying operational success. Some of the operating units have been plagued with scrubber and the line plugging and scale buildup. Most problems, however, have been mechanical related. It has been demonstrated that better than 90 weight percent SO_2 removal can be achieved with alkaline scrubbers.[3] Particulate control is claimed by manufacturers to be 99+ weight percent. The wet scrubbing technique could be an especially attractive control method used in conjunction with power plants burning low sulfur coal, due to the aforementioned resistivity problems that electrostatic precipitators face.

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[2] Some studies on stack emissions from lignite-fired power plants; Gronhovd, Tufte, and Selle; May 9, 1973.

[3] Engineering and Mining Journal, page 78, December, 1972

Continued operating problems may prove to be a constraint to development of coal reserves in the NGP. Wet scrubbers, in general, have a slightly lower capital cost but higher operating costs than electrostatic precipitators. Wet scrubbers, however, offer the advantage of requiring less physical space than an electrostatic precipitator or fabric filter.

Fabric filters or baghouses have not been applied to very large utility boilers, due primarily to cost. The capital investment required for a fabric filter is somewhat greater than for an electrostatic precipitator, and the operating costs are also greater. Filters can provide excellent particulate removal (99.5+ weight percent) and could be used in conjunction with the use of dolomite injection to recover some SO_2. Primary problems that could occur with the use of fabric filters would be the high volume of gas to be handled, the abrasiveness of the material being collected, and the effect of any SO_2 and possible aerosols in the flue gases on the life of the bags. Caking of the bags would require frequent shaking. It would not appear that fabric filters will make any large inroads to pollution control practices by the utility industry, unless demands are placed upon the industry to control their submicron particle size emissions. This is the size range of particulate matter which most predominantly affects visibility as well as being more easily taken into the respiratory system. A large segment of the trace elements in the stack gases are also present in this size range. This latter fact could provide the impetus for increased application of baghouses.

Nitrogen oxides emission control has been achieved almost entirely through combustion modification techniques. Only a few wet scrubber pilot plant developments using a caustic scrubbing solution have been initiated. Only very preliminary results are available at the present time. The combustion modifications employed have been aimed at reducing the firebox temperature, since formation of NO is favored at higher temperatures. Techniques such as flue gas recirculation, off stoichiometric combustion, reduced air preheat, selective burner service, low excess air, and operation at throttled load conditions have successfully reduced NO formation.

The previously mentioned control techniques and equipment is certainly not an exhaustive discussion of the methods being employed today. They do, however, constitute the majority of the effort being expended upon pollution control activities. Methods such as catalytic oxidation, electrostatic scrubbing, and coagulation should be provided with further research effort. A much more complete discussion of control techniques, is presented in Section VII of this report. A special report on each type of collection device will be published during the course of the next year by this task group.

The full impact of thermal discharges, wet cooling and dry cooling must be assessed. If, for instance, dry cooling is employed and a wet scrubber is installed, a source of water obviously must still be available. Also, energy consumption must be looked at for the various options to be sure the environment is not being asked to accept a larger burden in one segment than it is being benefitted by in another segment.

Research and development must be advanced if the environment is to be provided with adequate safeguards in conjunction with the anticipated mineral resource development. One of the prime areas of research and development work should center upon wet scrubbing techniques. Because of its inherent capability of both particle and gas collection, the wet scrubber is a potentially attractive control device. One problem yet to be solved is the disposal of the captured sulfur compounds ($CaSO_4$ or $CaSO_3$ with lime scrubbing). The sludge resulting from the collection of SO_2 represents a significant portion (about 40 percent for a 1% sulfur coal) of the solids that a plant must dispose of. Utilization of this solid waste material would make wet scrubbing even more attractive. Until utilization or safe disposal is perfected, the environment is trading an air pollution problem for potential solid waste and/or water pollution problems. Recent applications have indicated safe disposal.

3.9 MATERIALS OF CONSTRUCTION

Although indirectly related to the atmospheric constraints to the NGP development, the materials of construction required to construct the fuel conversion facilities and to operate the mines may provide a very real world type constraint. The backlog of orders for pollution control equipment, the long lead time to get delivery of electrical equipment, and the constraints upon materials fabrication facilities will serve to at least be a factor in timing of the proposed development, if not a confining factor in the magnitude of development.

3.10 MANPOWER

The projected mineral resource development in the NGP will place a heavy demand upon the labor market. The demand will be upon engineers, draftsmen, skilled and unskilled laborers, and others. Manpower must be available to design the facilities, to construct them, and finally the permanent force to operate and maintain the facilities. To put these ideas into perspective, it is suggested[4] that an increase of more than 40,000 megawatts of installed generating capacity may be placed in operation between now and 2000. Assuming an average of 400 employees to operate a mine and a 1000 megawatt plant, the projected development would require about 16,000 people directly. This level of manpower plus the attendant engineering and design manpower requirement will be a constraint and/or impact upon the NGP. When the above coal fired power generating plant figures are coupled with all of the other mineral resource development, it is easy to show the heavy labor force demand.

3.11 FINANCING

Another indirectly related factor (to the atmospheric environment) that could prove to be a significant constraint is project financing. It has been seen already that American industry is going overseas for the

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4. Energy Resources Work Group Report

funding of projects. This has happened in the oil and gas industry and the electric utility industry, as two examples, already. The Public Service Company of Colorado recently announced the negotiation of a loan from lending institutions in London and Brussels. A major oil company earlier this year divested part of its operating revenues in exchange for crude oil supply from a mid-East nation.

Looking once again, as an example, at the projected fossil fuel fired power generating capacity of 40,000 megawatts, a capital investment of $10 to $15 billion dollars will be required by the electric utility industry.[5] It is easy to see why more and more power developments are funded by power company consortiums. There are futher estimates that capital expenditures in the entire energy industry, including mining, petroleum, distribution, etc. will run as high as $500 billion by 2000. As a means of comparison, our present gross national product (GNP) is about $1,000 billion.

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[5] Estimated from approximate cost of $275 million for a 1,000 megawatt plant.

REFERENCES

1. Southwest Energy Study, Appendix E, Report of the Meteorology Work Group

2. Some studies on stack emissions from lignite-fired power plants; Gronhovd, Tufte, and Selle; May 9, 1973.

3. Engineering and Mining Journal, page 78, December, 1972

4. Energy Resources Work Group Report

5. Estimated from approximate cost of $275 million for a 1,000 megawatt plant.

SECTION IV

DEVELOPMENT SCENARIOS AND RELATED ATMOSPHERIC EMISSIONS

4.1 PROJECTED DEVELOPMENT LEVELS

Work Group G (National Energy Considerations) was charged with the responsibility of estimating the extent of mineral resource development in the NGP. A draft report entitled, "National and Regional Energy Considerations" was subsequently issued. It contained projections of estimated installed generating capacity, estimated coal gasification development, and estimated export mine activity. A time schedule showing when certain types of development would occur was provided along with some assumptions as to how the data contained in the report were generated. Projections were made for three levels of development, i.e. Base (Scenario I), Most Probable (Scenario II) and Extensive (Scenario III). Data for Scenario II are contained in Tables 5.1 through 5.13 in the draft report. Data for Scenario I are found on pages 96-98 of Section D and data for Scenario III were found on pages 101-108 of Section E. Using the data mentioned above, the number of power plants, the number of gasification plants, estimated installed generating capacities and estimated gasification capacities were calculated and are summarized in Tables IV-1 through IV-3.

Work Group B (Mineral Resources) was charged with locating the projected fuel conversion facilities and estimating where new mines would be located and what existing mines would be expanded. One basic assumption of this work group was that expansion of existing mines would handle all increased demands for coal until 1985.

TABLE IV-1

Increased Number of Coal Fired Power Plants (P.P.) and Coal Gasification (C.G.) Plants

	Scenario I		Scenario II		Scenario III	
	P.P.	C.G.	P.P.	C.G.	P.P.	C.G.
Montana						
1985 (1)	1	0	1	3	1	8
2000 (2)	5	0	5	6	5	15
Nebraska						
1985	1	0	1	0	1	0
2000	1	0	1	0	1	0
North Dakota						
1985	7	0	7	2	7	6
2000	8	0	13	7	13	17
South Dakota						
1985	2	0	2	0	2	0
2000	2	0	2	0	2	0
Wyoming						
1985	2	0	2	2	2	6
2000	3	0	3	3	3	9
NGP Total (1985)	13	0	13	7	13	20
NGP Total (2000)	19	0	24	16	24	41

(1) Total increase in plants from 1974 to 1985--obtained from Table 5.14 of work group G report
(2) Total increase in plants from 1974 to 2000--obtained from Table IV-5 of work group B report

TABLE IV-2

Projected Installed Generating Capacity, Megawatts (1)

	Montana	Nebraska	North Dakota	South Dakota	Wyoming	TOTAL
Existing as of January 1974	345	1534	862	252	1535	4,198
Scenario I -- Base						
1985	3101	3670	4125	1504	3893	16,293
2000	9100	4950	7460	3050	8455	33,015
Scenario II -- Most Probable						
1985	3101	3670	4125	1504	3893	16,293
2000	9100	6920	14,910	6060	8455	45,445
Scenario III -- Extensive						
1985	3101	3670	4125	1504	3893	16,293
2000	9100	6920	14,910	6060	8455	45,445

(1) Data obtained from pages 69-74, 96-98, and 101-108 of work group G draft report

TABLE IV-3

Estimated Gasification Capacity, MM SCFD (1)

	Montana	Nebraska	North Dakota	South Dakota	Wyoming	NGP TOTAL
Existing as of January 1974	0	0	0	0	0	0
Scenario I						
1985	0	0	0	0	0	0
2000	0	0	0	0	0	0
Scenario II						
1985	750	0	500	0	500	1750
2000	1500	0	1750	0	750	4000
Scenario III						
1985	2000	0	1500	0	1500	5000
2000	3750	0	4500	0	2250	10,500

(1) Data obtained from Table IV-6 of work group B report

Tables IV-4 through IV-6 were prepared by work group B and are provided herein for reference. There are inconsistencies regarding the installed generating capacity projections as developed by work groups B and G. This is illustrated by comparing the data presented in Tables IV-2 and IV-5 for the year 2000.

This work group (D) attempted to obtain specific knowledge regarding proposed coal gasification plants and power plants because of the need to calculate atmospheric emissions loadings. It was thought that this "specific site" information would help clarify some of the assumptions that were necessarily made by other work groups. State planning agencies, State environmental control agencies, and Governors' staff were contacted in order to obtain this specific data. Also, FPC 10-year plans, newspaper articles and private communication with the utility industry were relied upon to gather specific data. This data gathering effort has resulted in the information shown in Tables IV-7 and IV-8. We have labeled these data as Scenario IV. These data are meant to be applicable only through the year 1985 since most specific planning efforts by the utilities industry only extend about 10 years.

An assessment of the estimated increase in emissions in the NGP resulting from the projected development was made. In order to make a meaningful estimate of emissions, a consistent basis was chosen for estimating the emissions from the power plants and gasification plants. An annual load factor of 75 percent was chosen. Also a figure of 10,500 BTU/kwh was chosen as applicable to all new power plants. It was also assumed that the emissions would conform exactly to the EPA new source performance standards (NSPS) where applicable. Emissions estimates for pollutants and/or sources not covered by a NSPS were made based upon standard emission factors (EPA publication AP-42) and draft environmental analyses and other reports (for coal gasification plant emissions). The emissions calculated for an "average" power plant and an "average" coal gasification plant in the aforementioned manner should represent the maximum or worst case emissions to be expected from these sources. These data are summarized on Tables IV-9 and IV-10. In many instances plants will be and are being designed to emit lesser quantities of pollutants than the quantities shown in these tables. These situations should be evaluated on a case-by-case basis. Using the emissions shown in Tables IV-9 and IV-10 and the projected development shown in Tables IV-2, IV-3, IV-7 and IV-8, increased emissions for the NGP and by State were calculated. NGP summary data for power plants and coal gasification plants are shown on Tables IV-11 and IV-12, respectively, for Scenarios I-IV. Individual State data are shown in Tables IV-13 through IV-22. Total State wide (not study area portion of the State) 1972 emissions for the criteria pollutants are presented in Tables IV-23. Table IV-24 provides the comparison by pollutant between the state-wide emissions and the projected increases from the fuel conversion facilities.

We have only considered the direct effect of the fuel conversion facilities upon atmospheric emissions loadings. It would be desirable to consider the attendent activities associated with these facilities such as mining, road building, travel, increased population, and all of the other "secondary" effects. Unfortunately, data does not exist for us to get a handle on the magnitude of these emissions. It is probably safe to say, however, that they may be significant. Extensive work will be performed in this area in FY 75. See Section X of this report for more details.

Table IV-4

Northern Great Plains Development Forecasts

Gasification[1]

Development Forecast State	1980		1985		2000	
	Total No. of plants	Total coal requirements (MMtpy)[2]	Total No. of plants	Total coal requirements (MMtpy)[2]	Total No. of plants	Total coal requirements (MMtpy)[2]
Base forecast						
(No development of gasification projected)						
Most probable forecast						
Wyoming	--	--	2	15.5	3	24.2
Montana	--	--	3	22.2	6	46.3
North Dakota	--	--	2	20.1	7	69.7
Extensive development forecast						
Wyoming	--	--	6	50.4	9	76.1
Montana	3	23.2	8	62.9	15	118.3
North Dakota	4	40.2	6	59.9	17	172.2

[1] Gasification plants are projected to be 250 MMacfd capacity of SNG.

[2] Tonnages based upon 137.5 X 10^{12} Btu per year and upon average analysis of coal in vicinity of projected site.

Table IV-5

Northern Great Plains Development Forecasts

Power Generation

Development forecast1/ State	Number of new plants after 1985	Coal requirements of new plants after 19854/	New capacity after 1985 (megawatts)	Cumulative capacity in year 2000 (megawatts)
Base forecast				
Wyoming	1	4.7	1,2002/	5,3003/
Montana	4	15.6	4,100	6,800
North Dakota	1	5.7	1,200	5,800
Most probable forecast				
Wyoming	1	4.7	1,2002/	5,3003/
Montana	4	15.6	4,100	6,800
North Dakota	6	37.6	7,500	12,000
Extensive development forecast				
Wyoming	1	4.7	1,2002/	5,3003/
Montana	4	15.6	4,100	6,800
North Dakota	6	37.6	7,500	12,000

1/ New mines were not projected to fuel power generation plants for the year 1985, assuming that such requirements will be met by the expansion of existing mines.

2/ Assume 700 megawatts generated outside NGPRP area in Wyoming.

3/ Includes all of Wyoming.

4/ Tonnages based upon 65 X 10^{12} Btu per year and upon average analysis of coal in the vicinity of the projected site.

Table IV-6

Northern Great Plains Development Forecasts

Export

Development forecast State	Tonnages at new mines and total tonnages (MMtpy)					
	1980		1985		2000	
	New mine capacity	Cumulative capacity	New mine capacity	Cumulative capacity	New mine capacity	Cumulative capacity
Base forecast[1]						
Wyoming	--	25	--	29	2	31
Montana	--	26	--	28	2	30
North Dakota	--	6	--	6	2	8
Most probable forecast						
Wyoming	6	35	6[2]	44[3]	18[2]	65[3]
Montana	4	32	9	41	19	60
North Dakota	--	6	3	9	6	15
Extensive development forecast						
Wyoming	6	35	50[4]	93[3]	190[5]	296[3]
Montana	4	32	49	81	170	251
North Dakota	—	6	4	10	8	18

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[1] Year 1985 of the base forecast is assumed as the reference point for projecting new export mines. It is assumed that expansion of existing mines will meet requirements for this reference point.

[2] Assume exports of 3 MMtpy originating outside of NGPRP area in Wyoming.

[3] Cumulative export mine capacity includes all of Wyoming.

[4] Assume exports of 8 MMtpy originating outside of NGPRP area in Wyoming.

[5] Assume exports of 13 MMtpy originating outside of NGPRP area in Wyoming.

TABLE IV-7

Increased number of power plants and gasification plants

1985 - Scenario IV

	Power Plants	Coal Gasification Plants
Montana	1	0
Nebraska	1	0
North Dakota	9	1
South Dakota	1	0
Wyoming	3	1
NGP Total	15	2

TABLE IV-8

Projected Installed Generating Capacity, Megawatts

	Existing[1]	Increase[2]
Montana	345	2060
Nebraska	1534	1300
North Dakota	862	7112
South Dakota	252	100
Wyoming	1205	3190
NGP	4,198	13,762

(1)Statewide as of January 1974

(2)NGP increase by 1985

Table IV-9

Characteristics of an Average 1000 Megawatt Power Plant

Firing rate, electrical output		1000 megawatts
, heat input (1)		10.5×10^9 BTU/hr
Coal fired$^{(2)}$, ton/hour (3)		583.3
ton/year (4)		3.83×10^6
Steam produced, #/hour (5)		7.8×10^6
Flue gases, scfm (wet) (6)		2.1×10^6
Plant cost (7)		$\$260 \times 10^6$
Plant operating and service employees (8)		160
Mine employees (8)		250
Air emissions (9), #/hr (3), (TPY) (4)		
SO_2	12,600	(42,520)
Particulate	1,050	(3,540)
NO_x	7,350	(24,800)
HC	170	(560)
CO	580	(1,900)
Water consumption (10), cfs		20
, acre feet/year		15,000
, gpm		9,000

Notes

(1) at 32.5% plant efficiency, i.e., 10,500 BTU/kwh

(2) 9,000 BTU/# coal

(3) at 100% load factor

(4) at 75% load factor

(5) at 1000°F and 2500 psig

(6) at 20 percent excess air

(7) Reference: Colstrip E.I.S. (1-11) 1973 dollars

(8) Reference: Colstrip E.I.S. (2-180)

(9) assume compliance with NSPS

SO_2	$1.2\ \#/10^6$ BTU
Particulate	$0.1\ \#/10^6$ BTU
NO_x	$0.7\ \#/10^6$ BTU

(10) Wet cooling

Table IV-10

Characteristics of an Average Coal Gasification Plant

Plant capacity	250 MM SCFD
Gas quality	970 BTU/scf
Coal fired, ton per hour (1)	1110
heat input, BTU per year	157 x 10^{12}
ton per year (2)	8.84 x 10^{6}
Water required (3), acre feet per year	7000 --→ 30,000
, gpm	4000 --→ 18,000
, cfs	9 --→ 40
Steam required, ton per day	27,600
Oxygen required, ton per day	5500
By-products	tar tar oil naphtha phenols ammonia sulfur
Plant cost (3)	\$500 x 10^{6}
Plant employees (3)	1000
Number of gasifiers (3)	
gasification complex	30
power generation	10

Air emissions, #/hr (1), (Ton/year) (2)

1. Steam generation plant (4)

a. SO_2 (5)	4100	(16,340)
b. SO_2 (6)	400	(1,600)
c. SO_2 (7)	930	(3,720)
a. Particulate (5)	340	(1,350)
b. Particulate (6)	120	(480)
c. Particulate (7)	170	(680)
a. NO_x (5)	2390	(9,520)
b. NO_x (6)	500	(2,000)
c. NO_x (7)	1460	(5,840)

Table IV-10 (Continued)

Characteristics of an Average Coal Gasification Plant

a. HC	50	(200)
a. CO	190	(760)
2. Gasification complex (8)		
SO_2	1300	(5,190)
COS, H_2S	310	(1,240)
Particulate	140	(560)
NO_x	210	(840)
HC (10)	21,800	(86,870)

Notes

(1) at 100% stream factor

(2) at 91% stream factor

(3) El Paso E.I.S. and private communication with Panhandle Eastern

(4) 325 mwe equivalent

(5) Assume compliance with NSPS

(6) gas fired turbine and boilers

(7) coal fired with 85 percent S recovery

(8) with S recovery plant with tail gas incineration

(9) All data based upon coal with properties shown below
8870 BTU/#; 17.3% A; 16.5% moisture; 0.63% S

(10) Average of estimates contained in EPA draft report and private communication with industry

Table IV-11

TPY Estimated Emissions Increase -- Power Plants

NGP Summary

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	41,700	41,700	41,700	47,455
2000	99,330	142,180	142,180	--
Sulfur Oxides				
1985	500,600	500,600	500,600	569,610
2000	1,192,750	1,707,240	1,707,240	--
Nitrogen Oxides				
1985	291,850	291,850	291,850	332,290
2000	695,330	995,260	995,260	--
Hydrocarbon				
1985	8,780	8,780	8,780	9,960
2000	20,910	29,930	29,930	--
Carbon Monoxide				
1985	29,620	29,620	29,620	33,700
2000	70,570	101,010	101,010	--

TABLE IV-12

TPY Estimated Emissions Increase - Coal Gasification Plants

NGP Summary

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	0	13,370	38,200	3820
2000	0	30,560	78,310	--
Sulfur Oxides				
1985	0	150,710	430,600	43,060
2000	0	344,480	882,730	--
Nitrogen Oxides				
1985	0	72,520	207,200	20,720
2000	0	165,760	424,760	--
Hydrocarbon				
1985	0	609,490	1,741,400	174,140
2000	0	1,393,120	3,569,870	--
Carbon Monoxide				
1985	0	5320	15,200	1520
2000	0	12,160	31,160	--

TABLE IV-13

TPY Estimated Emissions Increase - Power Plants

MONTANA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	9,500	9,500	9,500	7,100
2000	30,180	30,180	30,180	--
Sulfur Oxides				
1985	114,070	114,070	114,070	85,260
2000	362,400	362,400	362,400	--
Nitrogen Oxides				
1985	66,500	66,500	66,500	49,740
2000	211,270	211,270	211,270	--
Hydrocarbon				
1985	2,000	2,000	2,000	1,490
2000	6,350	6,350	6,350	--
Carbon Monoxide				
1985	6,750	6,750	6,750	5,040
2000	21,440	21,440	21,440	

TABLE IV-14

TPY Estimated Emissions Increase - Power Plants

NEBRASKA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	7,360	7,360	7,360	4,480
2000	11,780	18,570	18,570	--
Sulfur Oxides				
1985	88,400	88,400	88,400	53,800
2000	141,390	222,930	222,930	--
Nitrogen Oxides				
1985	51,540	51,540	51,540	31,400
2000	82,420	129,960	129,960	--
Hydrocarbon				
1985	1,550	1,550	1,550	940
2000	2,480	3,910	3,910	--
Carbon Monoxide				
1985	5,230	5,230	5,230	3,180
2000	8,360	13,190	13,190	--

TABLE IV-15

TPY Estimated Emissions Increase - Power Plants

NORTH DAKOTA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	11,250	11,250	11,250	24,530
2000	22,740	48,420	48,420	--
Sulfur Oxides				
1985	135,060	135,060	135,060	294,370
2000	273,080	581,440	581,440	--
Nitrogen Oxides				
1985	78,740	78,740	78,740	171,720
2000	159,200	338,960	338,960	--
Hydrocarbon				
1985	2,370	2,370	2,370	5,150
2000	4,790	10,200	10,200	--
Carbon Monoxide				
1985	7,990	7,990	7,990	17,420
2000	16,160	34,400	34,400	--

TABLE IV-16

TPY Estimated Emissions Increase - Power Plants

SOUTH DAKOTA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	4,320	4,320	4,320	340
2000	9,640	20,020	20,020	--
Sulfur Oxides				
1985	51,820	51,820	51,820	4,140
2000	115,800	240,390	240,390	--
Nitrogen Oxides				
1985	30,210	30,210	30,210	2,410
2000	67,510	140,140	140,140	--
Hydrocarbon				
1985	910	910	910	70
2000	2,030	4,210	4,210	--
Carbon Monoxide				
1985	3,070	3,070	3,070	240
2000	6,850	14,220	14,220	--

TABLE IV-17

TPY Estimated Emissions Increase - Power Plants

WYOMING

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	9,270	9,270	9,270	11,005
2000	24,990	24,990	24,990	--
Sulfur Oxides				
1985	111,250	111,250	111,250	132,040
2000	300,080	300,080	300,080	--
Nitrogen Oxides				
1985	64,860	64,860	64,860	77,020
2000	174,930	174,930	174,930	--
Hydrocarbon				
1985	1,950	1,950	1,950	2,310
2000	5,260	5,260	5,260	--
Carbon Monixide				
1985	6,580	6,580	6,580	7,820
2000	17,760	17,760	17,760	--

TABLE IV-18

TPY Estimated Emissions Increase - Coal Gasification Plants

MONTANA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	0	5730	15,280	0
2000	0	11,460	28,650	--
Sulfur Oxides				
1985	0	64,590	172,240	0
2000	0	129,180	322,950	--
Nitrogen Oxides				
1985	0	31,080	82,880	0
2000	0	62,160	155,400	--
Hydrocarbon				
1985	0	261,210	696,560	0
2000	0	522,420	1,306,050	--
Carbon Monoxide				
1985	0	2280	6080	0
2000	0	4560	11,400	--

TABLE IV-19

TPY Estimated Emissions Increase - Coal Gasification Plants

NEBRASKA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	0	0	0	0
2000	0	0	0	--
Sulfur Oxides				
1985	0	0	0	0
2000	0	0	0	--
Nitrogen Oxides				
1985	0	0	0	0
2000	0	0	0	--
Hydrocarbon				
1985	0	0	0	0
2000	0	0	0	--
Carbon Monoxide				
1985	0	0	0	0
2000	0	0	0	--

TABLE IV-20

TPY Estimated Emissions Increase - Coal Gasification Plants

NORTH DAKOTA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	0	3820	11,460	1910
2000	0	13,370	32,470	--
Sulfur Oxides				
1985	0	43,060	129,180	21,530
2000	0	150,710	366,010	--
Nitrogen Oxides				
1985	0	20,720	62,160	10,360
2000	0	72,520	176,120	--
Hydrocarbon				
1985	0	174,140	522,420	87,070
2000	0	609,490	1,480,190	--
Carbon Monoxide				
1985	0	1520	4560	760
2000	0	5320	12,920	--

TABLE IV-21

TPY Estimated Emissions Increase - Coal Gasification Plants

SOUTH DAKOTA

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	0	0	0	0
2000	0	0	0	--
Sulfur Oxides				
1985	0	0	0	0
2000	0	0	0	--
Nitrogen Oxides				
1985	0	0	0	0
2000	0	0	0	--
Hydrocarbon				
1985	0	0	0	0
2000	0	0	0	--
Carbon Monoxide				
1985	0	0	0	0
2000	0	0	0	--

TABLE IV-22

TPY Estimated Emissions Increase - Coal Gasification Plants

WYOMING

	Scenario I	Scenario II	Scenario III	Scenario IV
Particulate				
1985	0	3820	11,460	1910
2000	0	5730	17,190	--
Sulfur Oxides				
1985	0	43,060	129,180	21,530
2000	0	64,590	193,770	--
Nitrogen Oxides				
1985	0	20,720	62,160	10,360
2000	0	31,080	93,240	--
Hydrocarbon				
1985	0	174,140	522,420	87,070
2000	0	261,210	783,630	--
Carbon Monoxide				
1985	0	1520	4560	760
2000	0	2280	6840	--

TABLE IV-23

Approximate Statewide Emissions - 1972, Tons Per Year

	Montana	Nebraska(1)	North Dakota	South Dakota(2)	Wyoming
Particulate	256,000	768,000	116,000	59,000	154,000
Sulfur Oxides	413,000	82,000	88,000	14,000	73,000
Nitrogen Oxides	110,000	87,000	144,000	78,000	106,000
Hydrocarbon	179,000	151,000	113,000	110,000	102,000
Carbon Monoxide	1,287,000	733,000	567,000	568,000	470,000

(1) 1971 data

(2) 1970 data

TABLE IV-24

Scenarios III and IV Emissions Comparison

Fuel Conversion Facilities Emissions Increase as % of 1972 State Total Emissions

	Montana	Nebraska	North Dakota	South Dakota	Wyoming
1985					
Particulate					
III	9	1	20	7	14
IV	3	1	23	1	8
Sulfur Oxides					
III	69	108	300	370	329
IV	21	66	359	30	210
Nitrogen Oxides					
III	135	59	98	39	120
IV	45	36	126	3	82
Hydrocarbon					
III	390	1	465	1	514
IV	1	1	82	1	87
Carbon Monoxide					
III	1	1	2	0	3
IV	1	1	3	0	2
2000					
Particulate					
III	23	1	70	34	27
Sulfur Oxides					
III	170	272	1080	1717	676
Nitrogen Oxides					
III	333	149	357	180	252
Hydrocarbon					
III	732	1	1317	3	772
Carbon Monoxide					
III	2	1	8	3	5

The information regarding existing and proposed power plants and coal gasification plants is shown in Table IV-25. Appropriate notes and definitions are explained in Table IV-26. Table IV-27 gives an example of the forms referred to by the column headed "plant code" on Table IV-25. Individual data sheets are available for inspection at the EPA Region VIII office for each of the plants listed.

Figure IV-1 shows the location of all existing power plants and proposed power plants and coal gasification plants in the NGP study area.

TABLE IV-25

NGP Power Plant Summary

Installed Generating Capacity, Megawatts

	Existing (1)	Proposed (2)	Total
Montana	345	2,060	2,405
Nebraska	1,534	1,580	3,114
North Dakota	862	7,232	8,094
South Dakota	252	100	352
Wyoming	1,535	3,190	6,225
TOTAL	4,528	14,162	18,690

(1) In operation as of January 1, 1974 - Statewide

(2) Proposed construction through about 1984 - NGP study area

MONTANA

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Sidney	Lewis and Clark - Montana-Dakota Utilities		44	coal	M-1
Billings	Corette - Montana Power		180	coal, gas	M-2
Billings	Bird - Montana Power		66	gas	M-3
Glendive	Glendive - Montana-Dakota Utilities		7	gas	M-4
Miles City	Miles City - Montana-Dakota Utilities		23	gas, diesel	M-5
Baker	Baker - Montana-Dakota Utilities (shut down)		10	gas	M-6
Libby	Libby - Libby Pacific Power & Light		25	diesel	M-7
TOTAL MONTANA EXISTING			345		
Colstrip	Colstrip - Montana Power, Puget Sound, Washington Power, PP&L, Portland G.E.	1	2060	coal	M-9
TOTAL MONTANA PROPOSED			2060		

B. Coal Gasification Plants - none

C. Nuclear Plants - none

NEBRASKA

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Alliance	Alliance - City of Alliance		17	coal	N-1
Fairbury	Fairbury - Fairbury Light		21	oil, gas	N-2
Fremont	Fremont - Fremont Dept. of Utilities		21	coal, gas	N-3
Fremont	Wright - Fremont Dept. of Utilities		41	coal, gas	N-4
Grand Island	Burdick - Grand Island Municipal Light		39	oil, gas	N-5
Grand Island	Pine Street - Grand Island Municipal Light		13	oil, gas	N-6
Hastings	Hastings - Hastings Utilities		54	oil, gas	N-7
Lincoln	A Street - Lincoln Commercial Light		9	coal, gas	N-8
Schuyler	Schuyler - Schuyler Dept. of Utilities		9	oil, gas	N-9
Lexington	Canady - Central Nebraska Public Power		109	oil, gas	N-10
Scottsbluff	Bluffs - Nebraska Public Power		42	oil, gas	N-11
Ogallala	Ogallala - Nebraska Public Power		8	oil, gas	N-12
Hallam	Sheldon - Nebraska Public Power		228	coal, gas	N-13
Lincoln	K-Street - Nebraska Public Power		29	coal, oil, gas	N-14
Bellevue	Kramer - Nebraska Public Power		113	coal, gas	N-15

NEBRASKA (Cont'd)

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Omaha	Jones - Omaha Public Power		160	coal, gas	N-16
Omaha	North - Omaha Public Power		601	coal, gas	N-17
Omaha	South - Omaha Public Power		20	oil, gas	N-18
TOTAL NEBRASKA EXISTING			1534		
Sutherland	Gentleman - Nebraska Public Power	1	1300	coal	N-19
Fremont	- Fremont Dept. of Utilities	2	80	coal	N-20
North Omaha	- Omaha Public Power	2	200	coal	N-21
TOTAL NEBRASKA PROPOSED			1580		

B. Coal gasification plants - none

C. Nuclear plants - none

NORTH DAKOTA

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Valley City	Valley City - Valley City Municipal		5	coal	ND-1
Grand Forks	Grand Forks - Minnkota		22	coal	ND-2
Stanton	Leland Olds - Basin Electric		216	coal	ND-3
Beulah	Beulah - Montana-Dakota Utilities		14	coal	ND-4
Stanton	Stanton - United Power Association		172	coal	ND-5
Mandan	Heskett - Montana-Dakota Utilities		100	coal	ND-6
Center	Young - Minnkota		250	coal, oil	ND-7
Devils Lake	Devils Lake - Otter Tail Power		13	coal	ND-8
Jamestown	Jamestown - Otter Tail Power		8	coal, oil	ND-9
Williston	Williston - Montana-Dakota Utilities		2	gas	ND-11
Wahpeton	Kidder - Otter Tail Power		21	coal	ND-14
Velva	Neal - Central Electric Power Corp.		39	coal	ND-15
TOTAL NORTH DAKOTA EXISTING			862		

NORTH DAKOTA (Cont'd)

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Stanton	Leland Olds - Basin Electric	1	440	coal	ND-3
Center	Young - Minnkota Power Coop	1	400	coal	ND-7
Underwood	Underwood - United Power Assoc.	1	972	coal	ND-16
Beulah	Beulah - Montana-Dakota Utilities	3	1200	coal	ND-18
Mandan	Mandan - Minnkota Power Coop	3	2500	coal	ND-19
?	- Basin Electric	2	500	coal	ND-20
?	- Montana-Dakota Utilities	2	100	coal	ND-21
?	- Northern States Power	2	800	coal	ND-22
?	- Ottertail	2	200	coal	ND-23
TOTAL NORTH DAKOTA PROPOSED			7112		

B. Coal Gasification

Beulah	Michigan - Wisconsin Pipeline Co.	3	250 MM SCFD	coal	ND-24

C. Nuclear Plants - none

SOUTH DAKOTA

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Huron	Huron - Northwestern Public Service		13	oil, gas	SD-1
Aberdeen	Aberdeen - Northwestern Public Service		13	coal, gas	SD-2
Mitchell	Mitchell - Northwestern Public Service		13	coal, gas	SD-3
Rapid City	French - Black Hills Power and Light		22	coal	SD-4
Lead	Lead Kirk - Black Hills Power and Light, Rushmore Electric Coop		32	coal	SD-5
Mobridge	Mobridge - Montana-Dakota Utilities		9	coal	SD-6
Sioux Falls	Lawrence - Northern States Power		48	coal, gas	SD-7
Sioux Falls	Pathfinder - Northern States Power		75	oil, gas	SD-8
Sioux Falls	Sioux Falls - Northern States Power (shutdown)		16	oil, gas	SD-9
Yankton	Yankton - Northwestern Public Service		11	gas, diesel	
TOTAL SOUTH DAKOTA EXISTING			252		
?	- Northwestern Public Service	2	100	coal	SD-13
TOTAL SOUTH DAKOTA PROPOSED			100		

B. Coal Gasification Plants - none

C. Nuclear Plants - none

WYOMING

A. Power Plants

City	Plant - Company	Reference Code	Size, Mw	Fuel	Plant Code
Wyodak	Simpson - PP&L, Black Hills P&L		28	coal	W-1
Glenrock	Johnston - Pacific Power & Light		750	coal, oil, gas	W-2
Kemmerer	Naughton - UP&L		710	coal	W-3
Sheridan	Acme - Montana-Dakota Utilities		12	coal	W-4
Osage	Osage - Black Hills P&L		35	coal	W-5
TOTAL WYOMING EXISTING			1535		
Wyodak	Simpson - Pacific Power and Light, Black Hills Power and Light	1	330	coal	W-1
Kemmerer	Naughton - Utah Power and Light	1	860	coal	W-3
Rock Springs	Bridger - Pacific Power and Light, Idaho Power Company	1	2000	coal	W-9
Wheatland	- Basin Electric	3	1500	coal	W-11
TOTAL WYOMING PROPOSED			4690		

B. Coal Gasification Plants

Bill	Peabody - Panhandle Eastern	3	280 MM SCFD	coal	W-10

C. Nuclear Plants - none

Table IV-26

Explanations for Table IV-25

A. Reference Code

This code explains how data regarding the proposed facilities was obtained.

1. E. I. S. or new source review
2. 10 year FPC plan
3. Private communication
4. Newspaper release

B. Plant Code

This code refers the reader to an individual data sheet which contains detailed information on that plant. Table IV-27 is an example of one of these data sheets.

C. NGP vs Statewide Totals

The existing plant total generating capacity illustrates a State total. The proposed generating capacity reflects proposed plants in the NGP study area only.

TABLE IV-27

Plant Code No._________

1. Location: State____________ County____________ City____________
2. AQCR - #____________ priority - particulate____________
   SO_2
3. Company
4. Plant name
5. Operating data

#1 #2 #3 #4

Installed generating capacity, Mw
Scheduled completion date if new
Type of boiler
Type fuel used
Coal fired capability
Amount of fuel used

Present emissions, #/hr
Particulate

Sulfur oxides

Nitrogen oxides

Allowable emissions, #/hr
Particulate

Sulfur oxides

Nitrogen oxides

Control device(s)
Particulate

Sulfur oxides

Actual heat input, 10^6 btu/hr

6. Plant heat rate, btu/kwh

7. Fuel data - coal %S avg.____________ range____________
   %A avg.____________ range____________
   btu/lb. avg.____________ range____________
   oil %S avg.____________ range____________
8. Fuel source
9. Electricity generation market
10. Cooling mechanism
11. Water consumption, cfs
12. Water source
13. Stack data
    height, m
    diameter, m
    exit temperature, °K
    cfm
    exit velocity, m/sec
14. Compliance schedule

#1 #2 #3 #4

15. Remarks

EXISTING AND PROPOSED ENERGY GENERATION FACILITIES IN THE NGPRP STUDY AREA

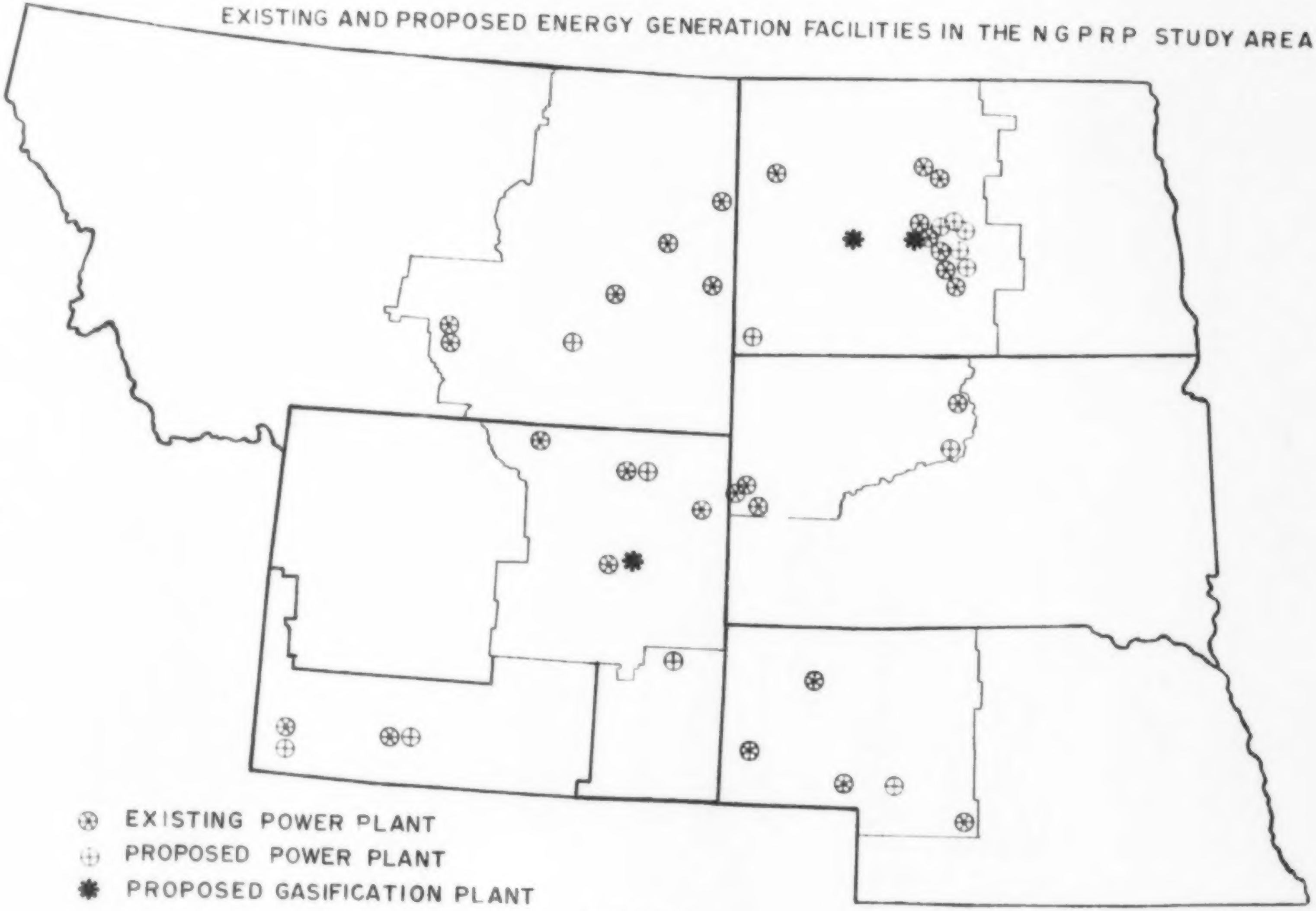

⊛ EXISTING POWER PLANT
⊕ PROPOSED POWER PLANT
✱ PROPOSED GASIFICATION PLANT

FIGURE IV-1

SCENARIO IV 1985

References

1. "National and Regional Energy Considerations", (draft), workgroup G.
2. "Report-Mineral Resources Work Group", (draft), workgroup B.
3. "Steam-Electric Plant Air and Water Quality Control Data", Summary Report for the year ending December 31, 1970; Federal Power Commission.
4. "Steam Electric Plant Factors", 1972, National Coal Association.
5. "Emissions from Processes Producing Clean Fuels", (draft) prepared for Environmental Protection Agency; Booz, Allen and Hamilton, Inc.,; March 1974.
6. "Detailed Environmental Analysis Concerning A Proposed Coal Gasification Plant"; Battelle Columbus Laboratories; February 1, 1973.
7. Private communication with Mr. Randolph Wood, Wyoming Department of Environmental Quality.
8. Private communication with Mr. John Goodyear, Wyoming Department of Economic Planning and Development.
9. Private communication with Mr. Bruce Heagen, Co-Chairman Governor's Energy Task Force - North Dakota.
10. Private communication with Mr. Lyle Randen, South Dakota Environmental Protection Agency.
11. Private Communication with Mr. Larry Holman, Montana Department of Environmental Sciences.
12. Private communication with Mr. Lynn Brandt, Montana Division of Energy Planning
13. Private communication with Mr. Andrew Freeman, Minnkota Power Coop.
14. Private communication with Mr. Thomas Smith, Montana Power
15. Private communication with Mr. Wally Lankmeyer, Montana Power

SECTION V

IMPACT OF CURRENT DEVELOPMENT ON AIR QUALITY

Atmospheric dispersion modeling has been employed to predict long term (annual) and short term (24-hr, 3-hr, and 1-hr) concentrations of particulate matter, sulfur dioxide, nitrogen oxides and hydrocarbons stemming from the emissions of eight existing or proposed regional coal-fired power plants and one hypothetical coal gasification plant.

The following coal-fired power plants have been investigated:

MONTANA: COLSTRIP Units 1 & 2 (treated as one source)
Units 3 & 4 (treated as one source)

NEBRASKA: GERALD GENTLEMAN PLANT Units 1 & 2 (treated as one source)

NORTH DAKOTA: LELAND OLDS Unit 1 (existing)
Unit 2

UNDERWOOD Units 1 & 2 (treated as one source)

MILTON YOUNG Unit 1 (existing)
Unit 2

WYOMING: JIM BRIDGER Units 1, 2, 3, 4 (treated as one source)

NAUGHTON Unit 1 (existing)
Unit 2 (existing)
Unit 3 (existing)
Units 4 & 5 (treated as one source)

WYODAK Unit 2

The above plants have been chosen because they represent significant additions to the existing electrical generating capacity of the five concerned states. In addition, the broad range of power outputs, 330 megawatts (Mw) to 2060 Mw, gives an excellent picture of the magnitude of the emissions and resulting potential problems. Also their combined capacity approximates CDPI development by 1985.

Concentration estimates were made for averaging times comparable to those specified by the State and National Ambient Air Quality Standards (Constraints, Section III).

The specific diffusion modeling procedures described below represent one modeling scheme for determining air quality impacts. These procedures should not be construed as the only ones acceptable to the Environmental Protection Agency.

5.1 DIFFUSION MODELS

5.1.1 Computations of Annual and 24-hr (elevated terrain) Concentrations

The annual and 24-hour elevated terrain particulate, sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and hydrocarbon (HC) concentration estimates were made using a computer program similar to that described by Martin (1971). Martin's program was modified by Burt (1973) to consider the effects of elevated terrain, to utilize Briggs (1969, 1971, and 1972) plume rise equations, and to provide a convenient computer printout which gives concentrations at specified grid points located along 16 radials fixed by the common 16 wind directions, N, NNE, NE, ENE, etc. A sample portion of the output of this model appears in Figure V-1. A detailed description of the model as it has been modified, and the computer code is given by Burt (1973).

This model is used to make concentration estimates for long term (annual) and short term (24-hr) averages incorporating flat terrain as well as elevated terrain. Because the model has not been verified in elevated terrain, computations were made for both flat and elevated terrain. With the flat terrain assumption, the concentration distribution given is dependent mainly on the wind frequency distribution, thus allowing one to assess wind effects independently of terrain. For the particulate concentration estimates the basic assumption is made that the particulate matter emitted from the point sources has an insignificant fall velocity, and is transported and diffused as a gas.

In addition, this model computes concentrations averaged over a 22½° sector centered on each of the sixteen radial lines. As a result, the estimates of pollutant concentrations are not as high as would be expected from a centerline concentration estimate. Sector averaging produces more realistic annual and 24-hr estimates. Over these longer time periods, the plume centerline can meander because of shifts in wind speed and direction, effectively reducing the concentrations along the original centerline of interest.

5.1.1.1 Modeling Assumptions and Details

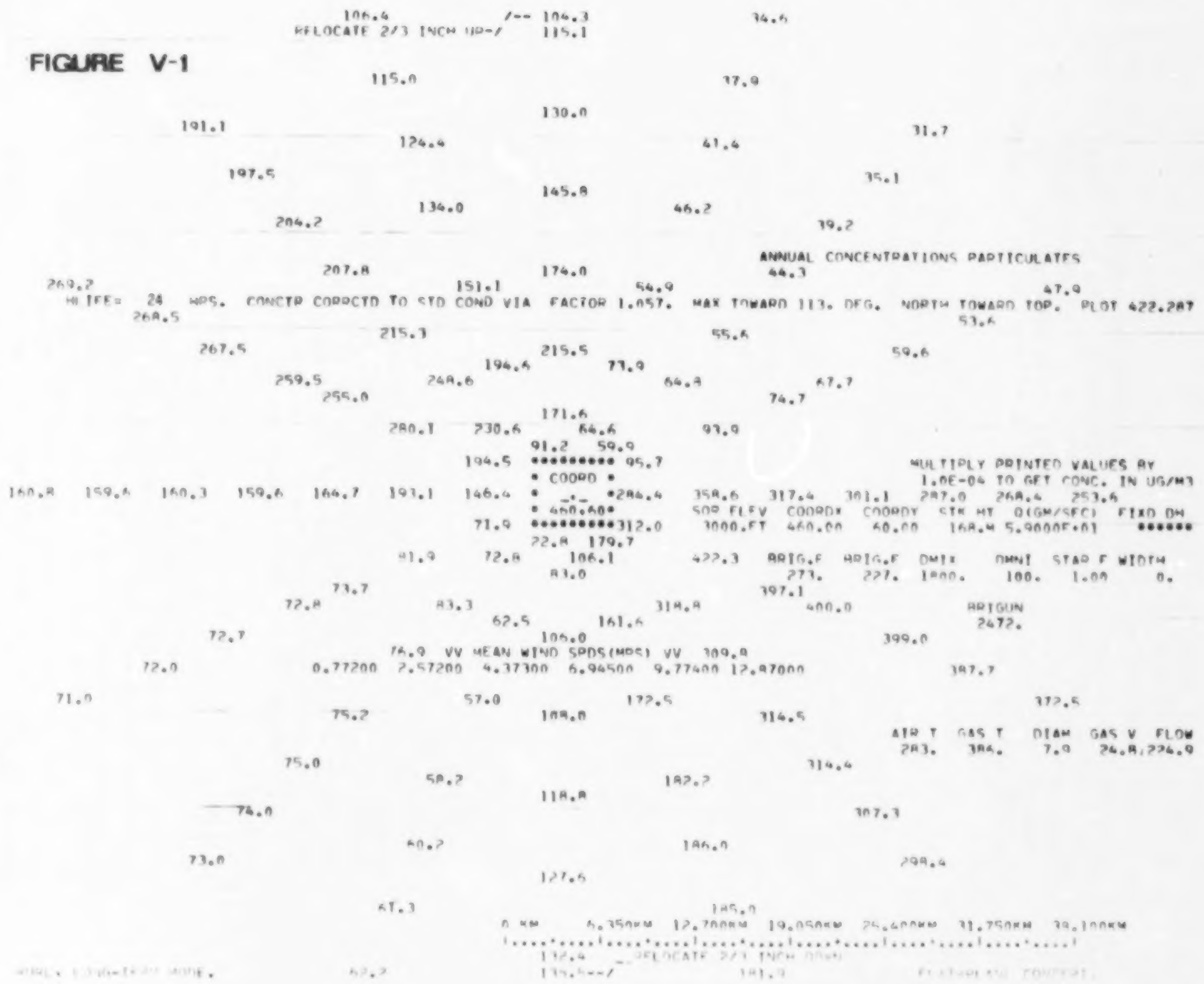
The following assumptions were used in the course of making the annual and 24-hr concentration estimates:

1. The wind speed, wind direction and atmospheric stability are assumed to be representative of the atmospheric layer between the surface and the mixing layer height.

2. Source emission rates are constant with time over the period of interest.

3. Pollution concentrations have been corrected to STP conditions of 25° C and a pressure of 760 mm of mercury.

FIGURE V-1



```
                                    106.4            /-- 104.3                 34.6
                              RELOCATE 2/3 INCH UP-/    115.1

                                       115.0                                37.9

                                                         130.0
                  191.1                                                                     31.7
                                          124.4                         41.4

                       197.5                                                           35.1
                                                         145.8
                                            134.0                    46.2
                            204.2                                                 39.2

                                                                                ANNUAL CONCENTRATIONS PARTICULATES
                                 207.8                   174.0                   44.3
    269.2                                       151.1          54.9                                          47.9
      HLIFE=  24  HRS.  CONCTR CORRCTD TO STD COND VIA  FACTOR 1.057.  MAX TOWARD 113. DEG.  NORTH TOWARD TOP.  PLOT 422.287
             268.5                                                                                    53.6
                                       215.3                             55.6
                    267.5                                215.5                                   59.6
                                                   194.6       73.9
                            259.5            248.6                   64.8             67.7
                                 255.0                                                 74.7
                                                         171.6
                                         280.1  230.6       64.6         93.9
                                                        91.2  59.9
                                                 194.5 ********* 95.7                                   MULTIPLY PRINTED VALUES BY
                                                       * COORD *                                          1.0E-04 TO GET CONC. IN UG/M3
160.8   159.6   160.3   159.6   164.7   193.1   146.4 *   _._   *286.4  358.6   317.4   301.1   287.0   268.4   253.6
                                                       * 460.60*        SOR ELEV  COORDX  COORDY  STK HT  Q(GM/SEC)  FIXD DH
                                                  71.9 **********312.0   3000.FT  460.00   60.00   168.4 5.9000E+01     ******
                                                       22.8  179.7
                                          81.9    72.8    106.1        422.3  BRIG.F  BRIG.F  DMIX    OMNI  STAR F WIDTH
                                                         83.0                  273.    227.  1800.    100.   1.00     0.
                             73.7                                                397.1
                        72.8            83.3             318.8           400.0            BRIGUN
                                                  62.5       161.6                          2472.
                   72.7                                 106.0                          399.0
                                           76.9  VV MEAN WIND SPDS(MPS) VV  309.8
             72.0                  0.77200  2.57200  4.37300  6.94500  9.77400 12.87000             387.7

     71.0                                         57.0              172.5                                      372.5
                             75.2                       188.0                   314.5
                                                                                        AIR T  GAS T   DIAM  GAS V  FLOW
                                                                                         283.   386.    7.9   24.8,224.9
                        75.0                                                    314.4
                                      58.2                        182.2
                                                        118.8
                ___74.0                                                               307.3

                                     60.2                          186.0
                19.0 73.0                                                                       298.4
                                                        127.6

                                         61.3                        185.0
                                                  0 KM    6.350KM  12.700KM  19.050KM  25.400KM  31.750KM  38.100KM
                                                  !....*....!....*....!....*....!....*....!....*....!....*....!
                                                        132.4   __RELOCATE 2/3 INCH DOWN
 RURAL LONG-TERM MODE.                 62.2             135.5--/              181.9                  FLAT-PLANE CONTOUR.
```

4. Scavenging or removal processes for the emitted particulate matter are assumed negligible. The pollutant half life, i.e., the time required for 50% of the original mass of the pollutant to be physically or chemically removed from the atmosphere, is thus assumed to be infinite in the case of particulate matter.

5. The half life for sulfur dioxide was chosen to be 24 hours. This is a simplification because the SO_2 half life is a complicated function of atmospheric conditions, such as relative humidity.

6. The half lives of nitrogen oxides and reactive hydrocarbons are presently in question. We have conservatively assumed that both NO_x and HC, like particulates, have an infinite half life. This is not valid physically, and this assumption will produce higher concentration estimates.

7. Under elevated terrain conditions; and unstable (A, B, C) and neutral (D) Pasquill stability categories (Turner, 1964), the plume centerline is assumed to rise or drop as the terrain changes, in effect, remaining at a constant height above the surface. Therefore, for these stability categories the concentration distribution is not affected by terrain. Under stable (E, F) stability categories the plume is assumed to remain at a constant elevation above sea level, consequently, impacting sufficiently high terrain. The plume flows up the sloping terrain and the concentrations in the plume are assumed to decrease linearly to zero at the point where the terrain is 400 meters above the plume centerline. Thus, for terrain 200 meters above the plume centerline, the concentration is reduced by a factor of 200/400 or one half. For terrain 400 or more meters above the centerline, the program sets all concentrations in the plume to zero. See Figure V-2.

8. For a given plant, all stacks with the same stack parameters (diameter, height, gas volume flow rate, and stack gas exit temperature) were treated as a single emission source with an emission rate equal to the sum of the individual emission rates of each stack, and with stack parameters identical to one of the individual stacks. For example, Units 3 & 4 of the Colstrip plant were treated as one 1400 Mw source rather than two 700 Mw units. Similarly, the Jim Bridger Plant was considered as a single 2000 Mw source, rather than four identical 500 Mw units. This assumption is made to reduce computational redundancy and gives a result identical to that obtained by computing separately the contribution from each source and then summing the results.

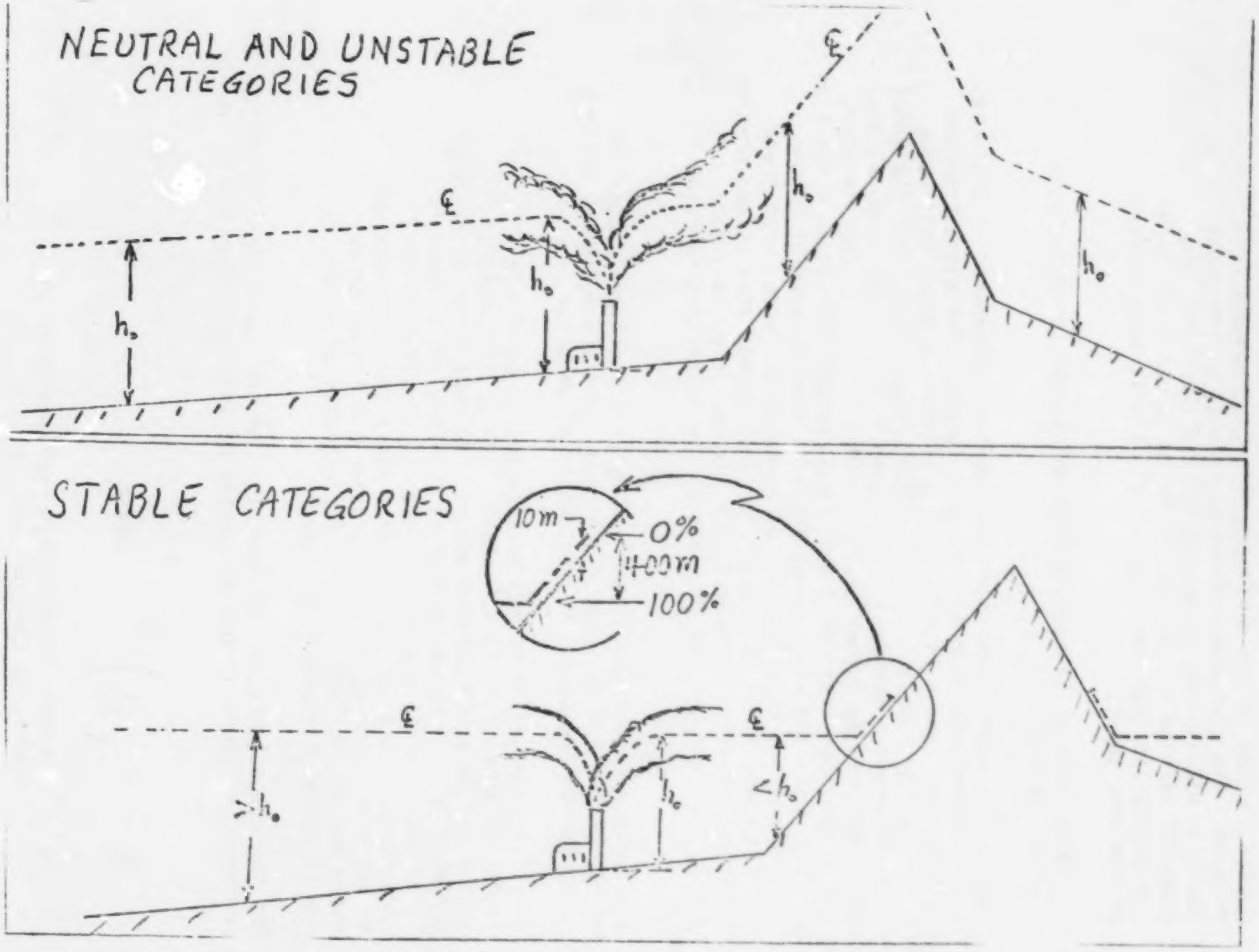

NEUTRAL AND UNSTABLE CATEGORIES
℄
h₀
h₀
℄
h₀
h₀
STABLE CATEGORIES
10m
0%
400m
100%
℄
℄
>h₀
h₀
<h₀

Figure V-2. A schematic depiction of the treatment by the model of plume height over terrain of varying height. From Burt (1973)

9. Several plants, such as the Naughton Plant near Kemmerer, Wyoming, have several different sized stacks. Therefore, each stack must be considered as a different source because of the different effective heights of release. The distance between the stacks at any given facility was assumed to be negligible; therefore, the computer carried out the multi-source calculations under the assumption that the bases of all stacks were located at the same point.

5.1.2 Computations of 24-Hour, 3-Hour and 1-Hour Concentrations (Flat Terrain)

Twenty-four-hour, three-hour and one-hour concentration estimates of SO_2 and non-methane hydrocarbons were computed for eight proposed power plants (SO_2) and a hypothetical gasification plant (HC) using UNAMAP air quality simulation models PTMAX, PTDIS, and PTMTP (National Technical Information Service). These models follow the computational procedures outlined by Turner (1970). PTMAX is used to compute short term (up to one hour) maximum ground level concentrations as a function of stability class and wind speed; PTDIS is used to predict ground level concentrations as a function of downwind distance, wind speed and stability; and PTMTP is similar to PTDIS except that it can predict concentrations resulting from multiple sources (e.g. Naughton). Tables V-1, V-2, and V-3 are portions of the respective computer outputs.

The concentrations calculated in Turner's model are centerline concentrations and are not sector averaged. The precautionary message which accompanies the computer printout is given below:

> Concentration estimates may be expected to be within a factor of three for: 1) all stabilities or distances of travel out to a few hundred meters. 2) neutral to moderately unstable conditions for distances out to a few kilometers. 3) unstable conditions in the lower 1000 meters of the atmosphere with a marked inversion above for distances out to ten kilometers or more. For other conditions these estimates become less reliable for extremes of stability and as travel distance increases.

Maximum concentrations representative of one averaging time period were converted to those of another period of interest using the following equation:

$$X_1 = X_2 \left(\frac{t_1}{t_2} \right)^{-.44} \quad \text{where}$$

X_1 = maximum concentration representative of averaging time period t_1

X_2 = maximum concentration representative of averaging time period t_2

TABLE V-1 PTMAX

```
ANALYSIS OF CONCENTRATION AS A FUNCTION OF STABILITY AND WIND SPEED.
1971 VERSION, D. B. TURNER.

EMISSION RATE (G/SEC) = 2268.00
PHYSICAL STACK HEIGHT (M) =  152.00
STACK GAS TEMP (DEG K) = 394.00
AMBIENT AIR TEMPERATURE (DEG K) = 293.
VOLUME FLOW (CU M/SEC) = 1015.00


 STABILITY      WIND SPEED     MAX CONC      DIST OF MAX     PLUME HEIGHT
                 (M/SEC)       (G/CU M)         (KM)             (M)

(A)   1            0.5       9.9000E+01     999.000(1)       4663.5(2)
      1            0.8       9.9000E+01     999.000(1)       2846.7(2)
      1            1.0       9.9000E+01     999.000(1)       2307.9(2)
      1            1.5       5.4320E-04       1.666          1590.2(2)
      1            2.0       5.8553E-04       1.476          1220.0(2)
      1            2.5       6.1525E-04       1.347          1014.3(2)
      1            3.0       6.3632E-04       1.253           870.6(2)

(B)   2            0.5       9.9000E+01     999.000(1)       4663.5(2)
      2            0.8       9.9000E+01     999.000(1)       2846.7(2)
      2            1.0       9.9000E+01     999.000(1)       2307.9(2)
      2            1.5       1.5756E-04       8.803          1590.2(2)
      2            2.0       1.8714E-04       6.963          1220.0(2)
      2            2.5       2.1160E-04       5.834          1014.3(2)
      2            3.0       2.3212E-04       5.080           870.6(2)
      2            4.0       2.6402E-04       4.109           690.0(2)
      2            5.0       2.8669E-04       3.517           583.2(2)

(C)   3            2.0       1.0946E-04      18.413          1220.0(2)
      3            2.5       1.2788E-04      14.904          1014.3(2)
      3            3.0       1.4391E-04      12.598           870.6(2)
      3            4.0       1.7027E-04       9.781           690.0(2)
      3            5.0       1.9041E-04       8.121           583.2(2)
      3            7.0       2.1739E-04       6.265           460.0(2)
      3           10.0       2.3713E-04       4.907           367.6(2)
      3           12.0       2.4228E-04       4.374           331.6(2)
      3           15.0       2.4328E-04       3.856           295.7(2)

(D)   4            0.5       9.9000E+01     999.000(1)       4663.5(2)
      4            0.8       9.9000E+01     999.000(1)       2846.7(2)
      4            1.0       9.9000E+01     999.000(3)       2307.9(2)
      4            1.5       9.9000E+01     999.000(3)       1590.2(2)
      4            2.0       9.9000E+01     999.000(3)       1220.0(2)
      4            2.5       1.8643E-05     177.189(3)       1014.3(2)
      4            3.0       2.3305E-05     131.082(3)        870.6(2)
      4            4.0       3.2380E-05      82.934           690.0(2)
      4            5.0       4.0841E-05      59.247           583.2(2)
      4            7.0       5.5264E-05      37.933           460.0(2)
      4           10.0       6.9949E-05      25.745           367.6(2)
      4           12.0       7.5807E-05      21.309           331.6(2)
      4           15.0       8.1250E-05      17.449           295.7(2)
      4           20.0       8.4805E-05      14.055           259.9(2)

(E)   5            2.0       1.0355E-04      89.299(1)        355.2(2)
      5            2.5       9.7537E-05      77.259(1)        340.6(2)
      5            3.0       9.2520E-05      68.880           329.5(2)
      5            4.0       8.4505E-05      57.839           313.3(2)
      5            5.0       7.8285E-05      50.786           301.7(2)

(F)   6            2.0       9.9000E+01     999.000(1)        320.6(2)
      6            2.5       9.9000E+01     999.000(1)        308.5(2)
      6            3.0       9.9000E+01     999.000(1)        299.3(2)
      6            4.0       9.9000E+01     999.000(1)        285.9(2)
      6            5.0       9.9000E+01     999.000(1)        276.2(2)
```

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TABLE V-2

```
DOWNWIND CONCENTRATIONS FOR SPECIFIC DISTANCES
DBT43 - JUNE 1973 VERSION,  D. B. TURNER


* * * SOURCE CONDITIONS * * *

SOURCE STRENGTH (G/SEC) =  2268.0
PHYSICAL STACK HEIGHT (M) = 152.0
STACK GAS TEMPERATURE (DEG K) = 394.0
VOLUME FLOW (M**3/SEC) =  1015.0

* * * METEOROLOGICAL CONDITIONS * * *

AMBIENT AIR TEMPERATURE (DEG K) = 293.0
STABILITY CLASS = 3  (C)
WIND SPEED (M/SEC) =  5.0
HEIGHT OF MIXING LAYER (M) = 600.0

FINAL EFFECTIVE HEIGHT OF EMISSION (M) =  583.2
DISTANCE TO FINAL EFFECTIVE HEIGHT (KM) =   1.735

DISTANCE  HEIGHT  CONCENTRATION     SIGY       SIGZ      CHI*U/Q
 (KM)      (M)     (G/CU M)         (M)        (M)      (SEC/M**3)
  6.500    583.2    3.19E-04       558.57     338.74     7.03E-07
  7.000    583.2    3.40E-04       596.81     362.49     7.49E-07
  7.500    583.2    3.53E-04       634.73     386.11     7.78E-07
  7.700    583.2    3.56E-04       649.81     395.51     7.85E-07
  8.000    583.2    3.59E-04       672.34     409.58     7.92E-07
  8.121    583.2    3.60E-04       681.40     415.25     7.93E-07
  8.300    583.2    3.60E-04       694.77     423.61     7.94E-07
  8.500    583.2    3.60E-04       709.67     432.04     7.94E-07
  9.000    583.2    3.57E-04       746.74     456.17     7.88E-07
 10.000    583.2    3.45E-04       820.13     502.32     7.60E-07
```

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TABLE V-3 PORTION OF PTMTP OUTPUT

```
MULTIPLE SOURCE MODEL DBT51, JUNE 1973 VERSION

* * * S O U R C E S * * *
 NO       Q         HP       TS        VS        D        VF         R          S
       (G/SEC)     (M)    (DEG K)   (M/SEC)    (M)   (M**3/SEC)   (KM)       (KM)

  1    1034.0     152.0    353.0     30.3      5.0     602.1      .000       .000
  2    2172.0     152.0    352.0     30.4      7.3    1279.3      .000       .000

* * * R E C E P T O R S * * *
 NO     RREC      SREC        Z
        (KM)      (KM)       (M)

  1     .000      .250       .0
  2     .000      .500       .0
  3     .000      .750       .0
  4     .000      .800       .0
  5     .000      .850       .0
  6     .000      .875       .0
  7     .000      .900       .0
  8     .000      .925       .0
  9     .000      .950       .0
 10     .000      .975       .0
 11     .000     1.000       .0
 12     .000     1.025       .0
 13     .000     1.050       .0
 14     .000     1.075       .0
 15     .000     1.100       .0
 16     .000     1.125       .0
 17     .000     1.150       .0
 18     .000     1.175       .0
 19     .000     1.200       .0
 20     .000     1.225       .0
 21     .000     1.250       .0
 22     .000     1.300       .0
 23     .000     1.350       .0
 24     .000     1.500       .0
 25     .000     2.000       .0
 26     .000     2.500       .0

* * * M E T E O R O L O G Y * * *
 NO   THETA       U      KST    HL        T
      (DEG)    (M/SEC)          (M)    (DEG K)

  1   180.0      3.0      1    2400.     233.

AVERAGE CONCENTRATIONS FOR  1 HOURS.
* * * R E C E P T O R   N U M B E R * * *
               1          2          3          4          5          6

 S          PARTIAL CONCENTRATIONS (G/M**3)

 1          3.225-16   7.737-06   4.479-04   5.223-04   5.681-04   5.806-04
 2          3.764-20   1.159-06   4.493-04   6.006-04   7.245-04   7.734-04

            TOTAL CONCENTRATION (G/M**3)

            3.225-16   8.896-06   8.972-04   1.123-03   1.293-03   1.354-03
* * * R E C E P T O R   N U M B E R * * *
               7          8          9         10         11         12

 S          PARTIAL CONCENTRATIONS (G/M**3)

 1          5.873-04   5.890-04   5.864-04   5.803-04   5.714-04   5.601-04
 2          8.132-04   8.442-04   8.669-04   8.820-04   8.903-04   8.927-04

            TOTAL CONCENTRATION (G/M**3)
```

X_1 and X_2; t_1 and t_2 must be expressed in the same set of units, e.g. ug/m^3 and hours, respectively. The above equation was based on data collected at a continuous, elevated point source. (Montana smelters Helena Valley, Montana, Area Environmental Pollution Study (1972)) This equation is very similar to that given by Hino (1968).

5.1.3 Inversion Break-up Fumigation Calculations

Calculations were made to estimate the worst case short term (1-hr) concentrations resulting from the break-up of inversions by solar heating and the resulting fumigation of the plume.

A temperature inversion is a situation where the air temperature increases with altitude. Often, ground based inversion layers occur on clear nights marked by light winds. The inversion layer of atmosphere is characterized by air that does not readily undergo the large convective-mixing motions that greatly assist in the dispersion of atmospheric pollutants. The plume from a stack undergoes little dilution or spreading as long as it remains in this inversion layer. Figure V-3 illustrates this phenomenon and also displays a graph of temperature versus height, illustrating the increase of temperature with altitude.

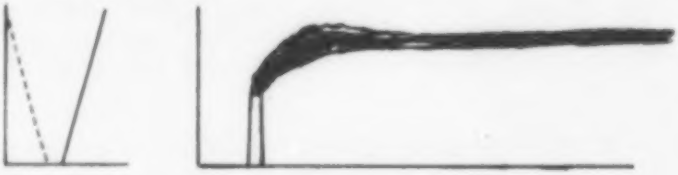
As the sun rises, solar radiation heats the ground making it warmer than the overlying air. The result of this incoming solar energy is to destroy the inversion from the ground up, progressively raising the height of the base of the inversion layer. The air lying beneath the base of the inversion has become more condusive to mixing atmospheric constituents (the air is then classified as neutral or unstable). As the base of the inversion rises, the air underneath becomes well mixed. Eventually, the rising base of the inversion penetrates the concentrated plume which can now come in contact with more unstable air. The unstable air can cause the plume pollutants to rapidly mix down to ground level, often building up significant short term concentrations. This process by which a plume is quickly mixed to the ground during the break-up of an inversion is referred to as fumigation and is graphically illustrated in Figure V-4.

The period of time that fumigation conditions can persist in the Northern Great Plains is not known at this time because of lacking meteorological data. It is thus difficult to compare calculated fumigation concentrations with air quality standards without knowing the time period to which the fumigation estimates are representative. We have assumed for illustrative purposes that fumigation persists for fifteen minutes. We caution that this assumption is not presently based on Northern Great Plains site specific data. It is entirely possible that further data collection and research studies will indicate longer periods of fumigation persistence, say 30 minutes or more. This would revise the calculated 1-hr concentrations upward.

Figures V-3 and V-4

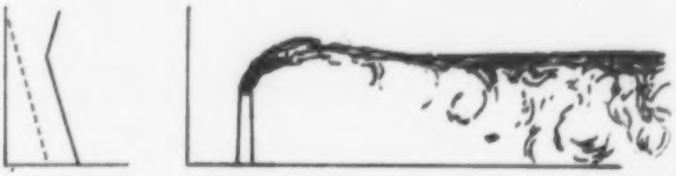
PLUME CHARACTERICS RELATED TO VARIOUS METEOROLOGICAL CONDITIONS

STABLE (FANNING)



V-3

NEUTRAL BELOW, STABLE ABOVE (FUMIGATION)



V-4

Fumigation calculations were performed using a model developed by Turner and Coventry (1972). This model differs somewhat from Turner's earlier treatment of fumigation in his Workbook of Atmospheric Dispersion Estimates (1970). Turner and Coventry have incorporated several assumptions in their model:

1. The pollutant plume has leveled off in the stable air of the inversion and the vertical extent of the plume is assumed to be 60% of the Briggs plume rise. Any further vertical diffusion is assumed negligible.

2. The time required to destroy the inversion from the stack top to some hight above by surface heating is given by Pooler (1965). This time is dependent on the strength of the inversion and the solar heating. Turner, like Pooler (1965) assumes that the maximum ground level concentrations occur when the pollutants emitted from the stack at the time when the base of the inversion has just reached stack top level are later mixed to the ground as the mixing layer penetrates the plume. This results in the minimum time after emission for plume travel in the inversion layer.

3. The net rate of heating by solar radiation is assumed constant and a value of 67 cal m^{-2} sec^{-1} (Pooler, 1965) is used. This assumption is a simplification since the rate of solar heating varies continuously throughout the day and also exhibits seasonal variations.

4. Vertical wind direction shear (the variation of wind direction with altitude) is only minimally accounted for in the model. Wind shear enhances the spreading and dilution of the pollutant plume. The model assumes the same constant wind speed throughout both the mixing and inversion layers. As Turner indicates, if there is vertical wind shear, the maximum fumigation concentrations will be approximately 50% of the estimates made by this model. This model will thusly provide conservatively high fumigation estimates.

5. The concentrations were calculated using a Gaussian distribution equation (e.g., eqn (3.6) Turner (1970)) that describes the situation where vigorous atmospheric mixing is limited to an unstable layer underneath a stable inversion layer. Turner has incorporated a correction factor to the pollutant emission rate in order to account for the fraction of the plume that is mixing between the base of the inversion and the ground.

The computer program incrementally increases the height of the base of the inversion; finds the time required for solar heating to destroy the inversion to these heights, and then calculates the fumigation concentrations associated with each inversion base height. The maximum of these fumigation concentrations is then chosen as the worst case fumigation concentration for the plant. Several facilities (Colstrip; Naughton; Olds; Young) have multiple stacks with differing stack parameters (height, volume flow, etc.). Computations were performed for each stack and graphs of concentration versus time (or equivalently, downwind distance) were made. The plots were graphically added to yield a resultant concentration vs distance curve representing the contribution from all stacks. The maximum of this resultant curve was chosen as the worst case fumigation concentration.

5.1.4 Meteorological Data Input

5.1.4.1 Computations of Annual Averages

Specific meteorological data required by the annual and 24-hour concentration dispersion model were not available at all of the plant sites. The NGPRP Air Monitoring Network (Section II) will help provide this data. In the interim, specific meteorological data from stations nearest the plant sites were obtained from the National Climatic Center (NCC), National Oceanic and Atmospheric Administration (NOAA) in Ashville, North Carolina. These data (STAR Program) are a joint frequency distribution of wind speed and direction and Pasquill stability classes. The stability classes are based on Pasquill's class structure, Turner (1964). Table V-4 lists the station name, period of record of the data and the facilities for which these data were assumed to apply. The Colstrip, Montana data were gathered and reduced by the Department of Earth Sciences, Montana State University. It was modified by the Region VIII EPA office, first incorporating the F and G stability category data under one stable F class; secondly, to reclassify the unrealistic A. B and F stability -- high wind speed events as D stability; and finally, to regroup the wind speed classes into only six, in order to place the data in the required format for the model calculations.

The STAR program data are used directly for determining the long term annual averages. A printout of the annual STAR program joint wind frequency distribution for Rock Springs is given in Table V-5. An individual matrix element in this table represents the annual frequency of occurrence of a wind blowing from a given direction, with a particular average speed while the atmosphere was categorized by one of six stability classes. All 576 elements (6 stability classes x 16 wind directions x 6 average speed classes) are normalized to sum to unity.

Additional meteorological data input required are a representative mixing layer height; ambient air temperature; and average station atmospheric pressures.

Values of the annual mixing layer heights at the plant sites were estimated from the mixing height isopleths developed by Holzworth (1972).

Table V-4

Star Program Station	Period of Record	Star Program Used for the Following Facilities
Bismarck, N.D.	1/67 - 12/71	Olds Plant, Stanton, N.D.
		Young Plant, Center, N.D.
		Underwood Plant, Underwood N.D.
Moorcroft, Wyoming	1/50 - 7/52	Wyodak Plant, Wyodak, Wyo.
		Hypothetical Gasification Plant
North Platte, Nebraska	1/60 - 12/64	Gentleman,Plant, Sutherland, Nebr.
Rock Springs, Wyoming	1/67 - 12/71	Bridger Plant, near Point of Rocks, Wyo.
		Naughton Plant, near Kemmera, Wyoming
Colstrip[1], Montana	11/71 - 11/72	Colstrip Plant, Colstrip, Montana

---

1. Data collected and reduced by the Department of Earth Sciences, Montana State University (1973).

TABLE V-5 STAR PROGRAM ANNUAL WIND FREQUENCY DISTRIBUTION FOR ROCK SPRINGS, WYOMING

STABILITY	SPD(MPS) WIND DIR	0.772	2.572	4.373	6.945	9.774	12.870
A	N	0.0003	0.0004	0.0	0.0	0.0	0.0
A	NNE	0.0001	0.0002	0.0	0.0	0.0	0.0
A	NE	0.0004	0.0004	0.0	0.0	0.0	0.0
A	ENE	0.0002	0.0003	0.0	0.0	0.0	0.0
A	E	0.0001	0.0001	0.0	0.0	0.0	0.0
A	ESE	0.0003	0.0004	0.0	0.0	0.0	0.0
A	SE	0.0002	0.0002	0.0	0.0	0.0	0.0
A	SSE	0.0001	0.0002	0.0	0.0	0.0	0.0
A	S	0.0002	0.0003	0.0	0.0	0.0	0.0
A	SSW	0.0002	0.0003	0.0	0.0	0.0	0.0
A	SW	0.0003	0.0004	0.0	0.0	0.0	0.0
A	WSW	0.0003	0.0005	0.0	0.0	0.0	0.0
A	W	0.0006	0.0006	0.0	0.0	0.0	0.0
A	WNW	0.0004	0.0005	0.0	0.0	0.0	0.0
A	NW	0.0003	0.0004	0.0	0.0	0.0	0.0
A	NNW	0.0003	0.0003	0.0	0.0	0.0	0.0
B	N	0.0021	0.0010	0.0009	0.0	0.0	0.0
B	NNE	0.0011	0.0010	0.0003	0.0	0.0	0.0
B	NE	0.0016	0.0010	0.0002	0.0	0.0	0.0
B	ENE	0.0007	0.0007	0.0002	0.0	0.0	0.0
B	E	0.0013	0.0006	0.0003	0.0	0.0	0.0
B	ESE	0.0005	0.0004	0.0003	0.0	0.0	0.0
B	SE	0.0004	0.0003	0.0002	0.0	0.0	0.0
B	SSE	0.0004	0.0004	0.0002	0.0	0.0	0.0
B	S	0.0018	0.0009	0.0004	0.0	0.0	0.0
B	SSW	0.0010	0.0007	0.0004	0.0	0.0	0.0
B	SW	0.0008	0.0011	0.0005	0.0	0.0	0.0
B	WSW	0.0018	0.0015	0.0010	0.0	0.0	0.0
B	W	0.0020	0.0025	0.0024	0.0	0.0	0.0
B	WNW	0.0020	0.0025	0.0020	0.0	0.0	0.0
B	NW	0.0011	0.0011	0.0008	0.0	0.0	0.0
B	NNW	0.0007	0.0007	0.0004	0.0	0.0	0.0
C	N	0.0005	0.0021	0.0018	0.0002	0.0001	0.0
C	NNE	0.0004	0.0015	0.0007	0.0	0.0	0.0
C	NE	0.0006	0.0023	0.0007	0.0	0.0	0.0
C	ENE	0.0005	0.0027	0.0018	0.0001	0.0001	0.0
C	E	0.0007	0.0020	0.0025	0.0002	0.0001	0.0
C	ESE	0.0004	0.0012	0.0014	0.0003	0.0	0.0
C	SE	0.0004	0.0009	0.0013	0.0001	0.0	0.0
C	SSE	0.0002	0.0011	0.0007	0.0001	0.0	0.0
C	S	0.0006	0.0028	0.0018	0.0005	0.0001	0.0
C	SSW	0.0003	0.0011	0.0014	0.0006	0.0001	0.0001
C	SW	0.0005	0.0023	0.0032	0.0005	0.0001	0.0
C	WSW	0.0009	0.0038	0.0073	0.0017	0.0001	0.0
C	W	0.0011	0.0049	0.0110	0.0044	0.0009	0.0001
C	WNW	0.0010	0.0037	0.0066	0.0025	0.0006	0.0001
C	NW	0.0004	0.0014	0.0026	0.0007	0.0001	0.0
C	NNW	0.0003	0.0012	0.0019	0.0002	0.0001	0.0
D	N	0.0004	0.0021	0.0026	0.0022	0.0011	0.0001
D	NNE	0.0004	0.0019	0.0018	0.0011	0.0002	0.0
D	NE	0.0004	0.0019	0.0034	0.0040	0.0022	0.0015
D	ENE	0.0005	0.0017	0.0080	0.0145	0.0082	0.0023
D	E	0.0005	0.0027	0.0079	0.0086	0.0024	0.0003
D	ESE	0.0004	0.0016	0.0037	0.0023	0.0003	0.0
D	SE	0.0005	0.0016	0.0044	0.0019	0.0001	0.0001
D	SSE	0.0006	0.0019	0.0034	0.0039	0.0005	0.0001
D	S	0.0009	0.0038	0.0086	0.0076	0.0038	0.0016
D	SSW	0.0007	0.0023	0.0078	0.0073	0.0042	0.0016
D	SW	0.0010	0.0034	0.0131	0.0104	0.0037	0.0007
D	WSW	0.0010	0.0051	0.0241	0.0322	0.0099	0.0030
D	W	0.0009	0.0050	0.0324	0.0771	0.0397	0.0095
D	WNW	0.0009	0.0028	0.0127	0.0254	0.0160	0.0042
D	NW	0.0003	0.0018	0.0047	0.0078	0.0039	0.0014
D	NNW	0.0002	0.0013	0.0022	0.0026	0.0008	0.0001
E	N	0.0	0.0028	0.0014	0.0	0.0	0.0
E	NNE	0.0	0.0019	0.0007	0.0	0.0	0.0
E	NE	0.0	0.0032	0.0013	0.0	0.0	0.0
E	ENE	0.0	0.0016	0.0043	0.0	0.0	0.0
E	E	0.0	0.0021	0.0071	0.0	0.0	0.0
E	ESE	0.0	0.0018	0.0035	0.0	0.0	0.0
E	SE	0.0	0.0027	0.0043	0.0	0.0	0.0
E	SSE	0.0	0.0029	0.0025	0.0	0.0	0.0
E	S	0.0	0.0043	0.0060	0.0	0.0	0.0
E	SSW	0.0	0.0043	0.0038	0.0	0.0	0.0
E	SW	0.0	0.0037	0.0097	0.0	0.0	0.0
E	WSW	0.0	0.0077	0.0201	0.0	0.0	0.0
E	W	0.0	0.0059	0.0212	0.0	0.0	0.0
E	WNW	0.0	0.0029	0.0080	0.0	0.0	0.0
E	NW	0.0	0.0016	0.0032	0.0	0.0	0.0
E	NNW	0.0	0.0009	0.0012	0.0	0.0	0.0
F	N	0.0027	0.0029	0.0	0.0	0.0	0.0
F	NNE	0.0019	0.0013	0.0	0.0	0.0	0.0
F	NE	0.0032	0.0033	0.0	0.0	0.0	0.0
F	ENE	0.0035	0.0042	0.0	0.0	0.0	0.0
F	E	0.0048	0.0056	0.0	0.0	0.0	0.0
F	ESE	0.0041	0.0041	0.0	0.0	0.0	0.0
F	SE	0.0043	0.0047	0.0	0.0	0.0	0.0
F	SSE	0.0036	0.0036	0.0	0.0	0.0	0.0
F	S	0.0081	0.0099	0.0	0.0	0.0	0.0
F	SSW	0.0057	0.0064	0.0	0.0	0.0	0.0
F	SW	0.0056	0.0081	0.0	0.0	0.0	0.0
F	WSW	0.0104	0.0139	0.0	0.0	0.0	0.0
F	W	0.0094	0.0124	0.0	0.0	0.0	0.0
F	WNW	0.0037	0.0050	0.0	0.0	0.0	0.0
F	NW	0.0026	0.0030	0.0	0.0	0.0	0.0
F	NNW	0.0021	0.0020	0.0	0.0	0.0	0.0

Average annual ambient air temperatures were determined from climatology data summarized in the pertinent Environmental Impact Statements and the National Climatic Atlas.

Average station atmospheric pressures were extracted from the standard atmosphere pressure-altitude relationship. Plant elevations (MSL) were used to determine the pressures.

5.1.4.2 Computations of 24-Hour, 3-Hour, and 1-Hour Averages (Elevated Terrain)

Seasonal and monthly STAR Program data were subjectively examined to locate the worst meteorological conditions for pollutant dispersal. For flat terrain, the greatest concentrations occur generally under A or B stability, but when terrain is considered, F stability conditions produce the highest concentrations.

In the computer model used for the 24-hour concentration estimates, the assumption that stability and wind persist from the specified direction for six of the twenty-four hours was made. The STAR Program data listing (e.g. Table V-5) was inspected to determine if instances of F stability, with a given wind direction, had a frequency of occurrence of at least six hours per month.

The largest frequencies of occurrence of F stability with winds blowing toward the direction of greatest terrain heights, lasting at least six hours per month, were chosen and are also listed in Table V-6. Terrain effects for four power plants were investigated. This is discussed in more detail in 5.2.2.

Temperatures and average mixing heights used were representative of the season in which the unlimited mixing worst case condition occurs. The sources of this data are the same as for the annual input. The mixing heights are great enough (2000-3600 meters) to allow for unlimited mixing. Twenty-four-hour estimates were scaled to three-hour and one-hour averages using the $t^{-.44}$ relationship discussed earlier.

5.1.4.3 Computations of 24-hour, 3-Hour, and 1-Hour Averages (Unlimited and Limited Mixing; Flat Terrain Assumption)

Two situations were chosen which will likely provide conservative short term concentrations:

1. Under unlimited mixing conditions, A stability and a 3 m/sec wind speed.

2. Under limited mixing (plume trapping) conditions, C stability and a 5 m/sec wind speed.

Table V-6

Meteorological Input Data for 24-Hour Concentration Estimates (Elevated Terrain)

Location	Stability	Wind Direction	Approximate Wind Speed Range (M/SEC)	Mixing Depth (M)	Terrain Considered
Bismarck (Olds Underwood Young)					no
Colstrip	F	N	<4	3600	yes
Moorcroft (Wyodak & Gasification Plant)	F	N	<4	2800	yes
Rock Springs (Bridger Naughton)	F	S, SSE	<4	2800	yes
North Platte (Gentleman)					no

Mixing heights for the unlimited mixing computations were taken from Holzworth (1972). A mixing height shallow enough to trap all plumes at a given facility under the above C stability limited mixing condition was chosen. In each limited mixing case, the chosen mixing height was just higher than the equilibrium height of the plume centerline. Detailed plume temperature data is not available to quantitatively address the question of whether the low level inversions used will be penetrated by the plume. Furthermore, the frequencies of occurrence and characteristics of low inversions at the plant sites are not available. Temperature soundings conducted at Bowman, Colstrip, Gillette, Glendive and Stanton will provide this much needed data on the frequencies of inversions and their characteristics.

Table V-7 lists the pertinent meteorological data employed in these calculations. These data, along with source conditions and selected downwind distances were inserted into the PTDIS and PTMTP programs and the maximum concentration for a given source was determined from the listings of concentration versus distance (see Tables V-2 and V-3).

The concentrations resulting from A stability calculations were assumed to be representative of 10 minute averages. The concentration-averaging time expression (Section 5.1.2) converted the 10 minute averages to one, three and twenty-four hour averages. Because it is possible for the C stability condition to persist for one hour, the concentrations in this case were assumed to be 1-hour averages. Three hour and twenty-four hour averages were extrapolated from the 1-hour concentrations using the above $t^{-.44}$ relationship.

5.1.4.4 Computations of Inversion Break-up Fumigation Concentrations

The fumigation model performs calculations for ten different wind speeds: 0.5; 0.8; 1.0; 1.5; 2.0; 2.5; 3.0; 4.0; 7.0; and 10.0 m/sec. The vertical potential temperature gradient, a quantity which describes the strength of the inversion, is also input as datum. Values of 0.01 and 0.02 ^{o}K/M were chosen to represent the vertical potential temperature gradients corresponding to Pasquill stability classes E and F respectively.

The maximum fumigation concentrations resulting from this model were assumed to persist for a 15-minute time period. 1-hour concentration estimates were obtained by assuming the remaining 45 minutes of the hour yielded zero contribution to the 1-hour average. Then by taking 25% of that 15 minute concentration the 1-hour average was obtained.

Table V-7

Meteorological Input Data for 24-Hour. 3-Hour and 1-Hour Estimates
Limited and Unlimited Mixing (Flat Terrain)

Plant	Meteorological Conditions			
	Stability	Wind Speed (M/SEC)	Mixing Height (M)	
Bridger	A	3	3600	unlimited mixing
	C	5	600	limited mixing
Colstrip	A	3	2400	unlimited mixing
	C	5	575	limited mixing
Gentleman	A	3	2400	unlimited mixing
	C	5	650	limited mixing
Olds	A	3	2000	unlimited mixing
	C	5	650	limited mixing
Naughton	A	3	3600	unlimited mixing
	C	5	650	limited mixing
Underwood	A	3	2000	unlimited mixing
	C	5	675	limited mixing
Wyodak	A	3	2800	unlimited mixing
	C	5	400	limited mixing
Young	A	3	2000	unlimited mixing
	C	5	500	limited mixing
Gasification Plant	A	3	2800	unlimited mixing
	C	5	200	limited mixing

5.2 EXISTING AND PROPOSED POWER PLANTS

5.2.1 Stack and Effluent Parameters

For the sake of consistency it was assumed that the emissions from each of the power plants would comply with the new source performance standards (NSPS). These standards are shown below. A deviation from this procedure was necessary in the calculation of nitrogen oxides

Particulate	0.1 pound per 10^6 BTU
Sulfur Oxides	1.2 pound per 10^6 BTU
Nitrogen Oxides	0.7 pound per 10^6 BTU

emissions from the three North Dakota plants. Because the NSPS for NO_x do not apply to lignite fired steam generating plants, a figure of 1.0 pound of NO_x per 10^6 BTU was used for the Olds, Underwood and Young plants. This figure was arrived at by looking at the values that were said to be attainable in the submitted Environmental Impact Statements. Emissions of carbon monoxide and hydrocarbons from power plants are minimal, and therefore, were not inserted into the model for air quality prediction purposes.

The assignment of emissions equal to those which would assure compliance with the NSPS may overstate the emissions which will actually result in some instances. Some of the plants are providing particulate matter control equipment which will result in particulate matter emissions equal to about 50 percent of that allowable by the NSPS. Also, sulfur oxides emissions for some plants will be less than that allowable by the NSPS because of either the low sulfur content of the coal or a company decision to install SO_2 removal equipment.

A 100 per cent load factor was used in order to calculate emissions to be used as input for the 24-hour air quality predictions. We felt it realistic to consider as a worst case condition that the power plant will operate at full capacity for a 24-hour period. A 75% annual load factor was assigned to the operation of the power plants in order to arrive at the emissions that may realistically be expected to occur over the period of a year. These emissions were used as input to the model for the prediction of annual air quality estimations.

The amount of coal burned and the heat content of the coal, hence the heat input to the plant required for the plant rated generating capacity, were obtained from detailed environmental analyses or impact statements submitted by the subject utilities.

The application of this emissions estimation technique allows us to eliminate several variables which could become points of contention. These variables include such things as amount of sulfur retained on the fly ash, variability of emissions as a function of boiler design, distribution of ash going to bottom ash and fly ash, and finally the effectiveness of certain types of pollution control devices.

The stack and effluent parameters for each of the above point sources are summarized and tabulated in Tables V-8 through V-15. The stack height and stack gas volume flow rate (the product of stack cross-sectional area and gas exit velocity) are important factors in determining ground level concentrations. All other factors being equal, more mixing and diffusion of pollutants occurs from taller stacks which release pollutants into a greater volume of atmosphere. Existing units have shorter stacks than new or proposed units at the same facility; for example, the Naughton complex has a 61 meter existing stack height and a 182 meter proposed stack height.

Stack gas volume flow rate significantly influences the height a plume can reach. Greater flow rates effectuate higher plume rises, all other conditions being identical. Higher plume heights cause pollutants to rise into a greater mixing volume of air, thus reducing the ground level concentrations. The Underwood Plant has a very large volume flow rate (1830 m^3/sec), a fact which will help explain the relatively small ground level concentrations encountered in the model results for that facility.

5.2.2 Terrain Considerations

U. S. Geological Survey Topographic maps (1:250,000 scale) were examined in order to assess the importance of terrain in the vicinity of each of the eight power plants. The topography was investigated within a 40 km radius of each plant. Changes in topographic relief in the proximity of the three North Dakota plants (Olds, Underwood and Young) and the Gentleman plant of Nebraska were judged to be insignificant, therefore, terrain effects were not considered for these plants.

The tall stacks, coupled with plume rise under stable (E, F) conditions (terrain model is used only under these conditions) produced clearances between the plume centerline and highest elevations on the order of two to three hundred meters. This clearance is equivalent to 2 to 3 vertical plume concentration distribution standard deviations (σ_z) for E stability at a distance of 20 km downwind from the source. The vertical plume concentration will fall to a value of approximately .01 times the plume centerline concentration in a vertical distance $3\sigma_z$. As a result, only a rather tenuous portion of the plume will intercept the terrain, and we have assumed this interaction to be negligible.

Table V-8

Summary of Point Source Modeling Input Data

1. Plant Jim Bridger

2. Location near Rock Springs, Wyoming

3. Unit(s) 1 + 2 + 3 + 4

4. Size (MW) 2000 total

5. Emissions (GM/SEC) Load Factor

	100%	75%
Particulates	252	189
Sulfur Dioxide	3024	2268
Nitrogen Oxides	1764	1323

6. Stack Data

Height (M)	152
Diameter (M)	7.4
Exit Temperature (°K)	394
Gas Exit Velocity (M/SEC)	23.6
Gas Volume Flow Rate (M^3/SEC)	1015

7. Source of Wind Data Rock Springs, Wyoming STAR Program

Table V-9

Summary of Point Source Modeling Input Data

1. Plant **Colstrip**

2. Location **Colstrip, Montana**

3. Unit(s)	**1 + 2**	**3 + 4**
4. Size (MW)	**660**	**1400**

5. Emissions (GM/SEC) Load Factor

	100%	75%	100%	75%
Particulates	**85**	**64**	**181**	**136**
Sulfur Dioxide	**1024**	**768**	**2172**	**1628**
Nitrogen Oxides	**597**	**448**	**1267**	**950**

6. Stack Data

Height (M)	152	152
Diameter (M)	5.03	7.32
Exit Temperature (°K)	352	352
Gas Exit Velocity (M/SEC)	30.3	30.4
Gas Volume Flow Rate (M^3/SEC)	602	1275

7. Source of Wind Data **Colstrip, Montana State University Data**

Table V-10

Summary of Point Source Modeling Input Data

1. Plant Gerald Gentleman

2. Location Sutherland, Nebraska

3. Unit(s) 1 + 2

4. Size (MW) 1300 total

5. Emissions (GM/SEC) Load Factor

	100%	75%
Particulates	158	118
Sulfur Dioxide	1884	1414
Nitrogen Oxides	1098	824

6. Stack Data

Height (M)	168
Diameter (M)	7.93
Exit Temperature (°K)	386
Gas Exit Velocity (M/SEC)	24.8
Gas Volume Flow Rate (M^3/SEC)	1225

7. Source of Wind Data North Platte, Nebraska STAR Program

Table V-11

Summary of Point Source Modeling Input Data

1. Plant Leland Olds

2. Location Stanton, N.D.

3. Unit(s)	(Existing) 1	2
4. Size (MW)	216	440

5. Emissions (GM/SEC) Load Factor

	100%	75%	100%	75%
Particulates	14	10	60	44
Sulfur Dioxide	324	243	711	533
Nitrogen Oxides	176	132	592	444

6. Stack Data

Height (M)	107	152
Diameter (M)	5.34	7.7
Exit Temperature (°K)	479	460
Gas Exit Velocity (M/SEC)	21.0	18.2
Gas Volume Flow Rate (M^3/SEC)	470	848

7. Source of Wind Data Bismarck, N.D. STAR Program

Table V-12

Summary of Point Source Modeling Input Data

1. Plant Naughton

2. Location Kemmerer, Wyoming

3. Unit(s)	(Existing) 1	(Existing) 2	(Existing) 3	4 + 5
4. Size (MW)	160	220	330	860

5. Emissions (GM/SEC) **Load Factor (%)**

	100	75	100	75	100	75	100	75
Particulates	17	13	23	18	35	26	106	80
Sulfur Dioxide	214	160	292	219	441	331	1275	957
Nitrogen Oxides	188	141	258	194	387	290	743	558

6. Stack Data

Height (M)	61	69	76	182
Diameter (M)	4.12	4.73	6.83	7.3
Exit Temperature (°K)	404	393	404	405
Gas Exit Velocity (M/SEC)	22.2	18.8	14.4	21.3
Gas Volume Flow Rate (M^3/SEC)	296	330	528	892

7. Source of Wind Data Rock Springs STAR Program

Table V-13

Summary of Point Source Modeling Input Data

1. Plant Underwood

2. Location Underwood, North Dakota

3. Unit(s) 1 + 2

4. Size (MW) 972 total

5. Emissions (GM/SEC) Load Factor

	100%	75%
Particulates	129	96
Sulfur Dioxide	1542	1157
Nitrogen Oxides	1285	964

6. Stack Data

Height (M)	152
Diameter (M)	10
Exit Temperature (°K)	358
Gas Exit Velocity (M/SEC)	23.3
Gas Volume Flow Rate (M^3/SEC)	1830

7. Source of Wind Data Bismarck, N.D. STAR Program

Table V-14

Summary of Point Source Modeling Input Data

1. Plant **Wyodak**

2. Location **Wyodak, Wyoming**

3. Unit(s) 1

4. Size (MW) 330

5. Emissions (GM/SEC) Load Factor

	100%	75%
Particulates	46	35
Sulfur Dioxide	552	414
Nitrogen Oxides	323	241

6. Stack Data

Height (M)	121
Diameter (M)	3.8
Exit Temperature (^oK)	400
Gas Exit Velocity (M/SEC)	27.4
Gas Volume Flow Rate (M^3/SEC)	311

7. Source of Wind Data Moorcroft, Wyoming STAR Program

Table V-15

Summary of Point Source Modeling Input Data

1. Plant Milton Young

2. Location Center, North Dakota

3. Unit(s)	(Existing) 1	2
4. Size (MW)	235	400

5. Emissions (GM/SEC) Load Factor

	100%	75%	100%	75%
Particulates	11	9	48	36
Sulfur Dioxide	617	463	573	430
Nitrogen Oxides	390	293	479	359

6. Stack Data

Height (M)	77	181
Diameter (M)	5.8	9.2
Exit Temperature (°K)	439	411
Gas Exit Velocity (M/SEC)	13.3	7.8
Gas Volume Flow Rate (M^3/SEC)	350	521

7. Source of Wind Data Bismarck, N.D. STAR Program

Annual and 24-hour calculations were made, however, for the Bridger, Colstrip, Naughton and Wyodak Plants with the effects of terrain considered.

Concentrations are calculated at 112 receptor points on the grid shown in Figure V-1. The receptor points lie along sixteen radial lines, with seven receptors located along each radial direction. Due to the characteristics of the computer line printer, the distances between the grid receptor points vary. Terrain data input consists of specifying the elevations of the 112 receptors, a task facilitated by overlapping of the receptor grid onto a USGS topographic map. The use of 1:250,000 scale maps meant that neighboring receptors on a given radial direction were separated by approximately 6 km. As an example, Table V-16 gives the receptor elevations (MSL) in feet for the Naughton Plant. This table shows that the highest terrain within 40 km of Naughton was in the NNW, N and NNE directions. The terrain in the neighborhood of the Bridger Plant was greatest in the WNW, NW, and NNW directions with two receptors at elevations 1200 feet above the Plant. Colstrip's highest terrain occurred towards the S and SSE, with maximum elevation changes relative to the plant of approximately 950 feet. Finally, Wyodak terrain had its highest elevations (400 feet above plant elevation) towards the South.

An important point to consider is that only 112 elevations along sixteen equally spaced radial lines define the terrain; therefore, the grid resolution is a function of the GRID size input parameter. Occasionally, higher elevations may occur within the sector defined by two radial lines, or between two receptor points on a given line. For example, Steamboat Mountain (elev. 8683 ft) near the Jim Bridger Plan (elev. 6700 ft) fell between the NNW and NW radial lines and was not considered in the calculations.

5.3 IMPACT OF POWER PLANTS ON AIR QUALITY

To summarize the results of the diffusion modeling, the long and short term concentration estimates will be compared to the various State and National Ambient Air Quality Standards. These standards are discussed and tabulated in the Constraints Section (III) of this report. The diffusion model output represents the contribution to the ambient air concentrations of pollutants from the power plants. It is vital to remember that background air quality levels must be considered along with the concentration increases produced by the plants in order to predict whether the air quality standards will be violated. Unfortunately, the available air quality data at the plant sites is very limited, and an unequivocal assessment of each plant's compliance with air quality standards is not presently feasible.

Table V-16

Receptor Elevations - Naughton Plant (Elevation 6925 FT)
(FEET, MSL)

N	7000	7400	7200	7400	8200	8200	8500
NNE	7000	7200	7200	7400	7400	7800	8000
NE	7000	7400	7200	7400	6800	6800	6800
ENE	7000	7100	7000	7000	6695	6700	6600
E	7000	7000	6900	6800	6800	6800	6800
ESE	6800	7050	6600	6600	6600	6600	6300
SE	6800	6900	6900	6600	6600	6600	6400
SSE	6800	7000	6800	6600	6750	6650	6600
S	6800	6850	6800	6700	7000	6900	6700
SSW	6900	7200	6800	7000	7200	7200	6800
SW	7800	7600	7400	7200	7000	7200	7400
WSW	7400	7900	7400	7400	7400	7100	7400
W	6800	7500	7000	7600	7600	7200	7200
WNW	6800	6800	6800	7200	6800	7000	7000
NW	6800	7200	7800	7800	7000	6800	7200
NNW	7600	6800	7600	7400	7300	7200	7200

The results of the computations are summarized in the following three tables:

1. Table V-17: Maximum Ground Level Annual Concentration Estimates: Particulates; SO_2; NO_x and HC. Flat Terrain Assumption.

2. Table V-18: Maximum One, Three and Twenty Four Hour SO_2 and HC Concentrations as a Function of Stability Class. Unlimited and Limited Mixing.

3. Table V-19: Maximum SO_2 and Hydrocarbon Concentrations Resulting from Inversion Breakup Fumigation.

Each of the above three tables lists the respective concentrations predicted at all the power plants for comparison. In addition, Table V-17 includes values of various parameters that influence the concentration estimates: emission rates; stack height; stack gas volume flow; and average annual afternoon mixing height. Larger values of stack height, stack gas volume flow and plume rise favor increased dilution and effectuate lower ground level concentrations, all other factors being equal. Lastly, all three tables list the downwind distance where the maximum concentrations occur.

As a precursor to the discussion of the air quality impacts of each power plant, we present two figures (V-5 and V-6) graphically summarizing the modeling results. The height of each bar represents the maximum predicted ambient SO_2 (Figure V-5) and particulate (Figure V-6) plant concentrations. These predictions do not incorporate plant background pollutant levels. The pertinent state and Federal ambient air quality standards appear on these figures for reference.

5.3.1 Montana: Colstrip Plant

5.3.1.1 Long Term Impacts

The available Colstrip background air quality data is presented in Table V-20 and have been combined with the worst case diffusion model concentration estimates to produce the maximum expected concentrations. For reference, the pertinent National and State Ambient Air Quality Standards are reproduced from Section III, and are enumerated in Tables V-21 and V-22.

Plant contributions to the annual ambient concentrations of particulates, sulfur dioxide and nitrogen oxides are small, the largest contribution being that of SO_2, 2 ug/m^3. The background levels of these

Table V-17

Maximum Ground Level Annual Concentration Estimates: Particulates; SO_2; NO_x and HC: Flat Terrain Assumption

Plant	Unit(s)	MW	Emission Rates (GM/SEC) Part	Emission Rates (GM/SEC) SO_2	Emission Rates (GM/SEC) NO_x	Stack Gas Volume Flow M^3/SEC	Stack Ht (M)	Mixing Height (M)	Maximum Concentration ($\mu G/M^3$) Part	Maximum Concentration ($\mu G/M^3$) SO_2	Maximum Concentration ($\mu G/M^3$) NO_x	Distance of Maximum Conc. (KM)
Bridger	1 + 2 + 3 + 4	2000	189	2268	1323	1015	152	2300	.3	3.3	1.9	25.4
Colstrip	1 + 2	660	64	768	448	602	152	2000	.1	1.1	.7	15.2
	3 + 4	1400	136	1628	950	1275	152	2000	.1	1.1	.7	25.4
	1 + 2 + 3 + 4	2060	200	2396	1398				.2	2.1	1.4	20.3
Gentleman	1 + 2	1300	118	1414	824	1225	168	1800	.08	.8	.6	9.2
Leland Olds	1	216	10	243	132	466	107	1500	.01	.3	.1	15.9
	2	440	44	533	444	948	152	1500	.02	.2	.2	24.8
	1 + 2	656	54	776	576				.03	.5	.3	19.7
Naughton	1	160	13	160	141	296	61	2300	.2	2.2	2.2	10.2
	2	220	18	219	194	330	69	2300	.2	2.7	2.2	10.2
	3	330	26	331	290	528	76	2300	.2	2.0	2.2	10.2
	4 + 5	860	80	957	558	892	182	2300	.1	1.2	.7	10.2
	1 + 2 + 3 + 4 + 5	1570	137	1667	1183				.7	8.2	6	10.2
Underwood	1 + 2	972	96	1157	964	1830	152	1500	.04	.4	.4	9.5
Wyodak	2	330	35	414	241	310	121	2000	.1	1.3	.7	15.2
Young	1	235	9	463	293	350	77	1500	.03	1.3	.8	11.4
	2	400	36	430	359	521	181	1500	.03	.3	.3	21.0
	1 + 2	635	45	893	652				.06	1.6	1.1	11.4
Gasification		250 MM SCFD	16	149	24	55	91	2000	.2	1.9	.3	3.8
Steam Plant		325	39	470	274	311	121	2000	.1	1.5	.7	9.2
Hydrocarbons (HC)												
Gasification Complex		250 MM SCFD		1753 (HC)		55	91	2000	22.7 (HC)			3.5

Table V- 18

Maximum One, Three and Twenty-Four Hour SO_2 and HC Concentrations as a Function of Stability Class

Unlimited and Limited Mixing

Plant	Unit(s)	Meteorological Conditions Stability	Meteorological Conditions Wind Speed (M/SEC)	Mixing Height (M)	Maximum SO_2 Concentrations (uG/M^3) 24 HR	Maximum SO_2 Concentrations (uG/M^3) 3 HR	Maximum SO_2 Concentrations (uG/M^3) 1 HR	Distance of Maximum Conc. (KM)	Maximum Particulate Concentrations (uG/m^3) 24 Hour
Bridger	1 + 2 + 3 + 4	A	3	3600	137	341	553	1.10	11
		C	5	600	115	287	465	8.85	10
Colstrip	1 + 2	A	3	2400	66	165	268	0.93	5
	3 + 4	A	3	2400	100	250	405	1.03	8
	1 + 2 + 3 + 4	A	3	2400	164	410	665	0.99	13
	1 + 2	C	5	575	48	119	193	6.88	4
	3 + 4	C	5	575	93	231	375	8.00	8
	1 + 2 + 3 + 4	C	5	575	139	348	564	7.75	12
Gentleman	1 + 2	A	3	2400	77	192	310	1.10	6
		C	5	650	63	158	256	9.00	5
Leland Olds	1	A	3	2000	20	49	80	0.93	1
	2	A	3	2000	29	72	117	1.08	2
	1 + 2	A	3	2000	47	118	192	1.02	3
	1	C	5	650	12	30	49	7.60	.5
	2	C	5	650	24	59	96	9.15	2
	1 + 2	C	5	650	36	89	144	8.75	2
Naughton	1	A	3	3600	24	59	96	0.75	2
	2	A	3	3600	30	75	122	0.78	2
	3	A	3	3600	33	83	135	0.85	3
	4 + 5	A	3	3600	52	131	212	1.06	4
	1 + 2 + 3 + 4 + 5	A	3	3600	126	315	511	0.93	10
	1	C	5	650	18	45	73	3.75	1
	2	C	5	650	22	56	91	3.90	2
	3	C	5	650	20	50	81	5.50	2
	4 + 5	C	5	650	43	107	173	9.00	4
	1 + 2 + 3 + 4 + 5	C	5	650	84	209	339	7.25	7
Underwood	1 + 2	A	3	2000	62	154	250	1.10	5
		C	5	675	50	120	194	9.50	4
Wyodak	2	A	3	2800	50	117	190	0.90	4
		C	5	400	51	123	200	5.00	4
Young	1	A	3	2000	52	131	212	0.85	1
	2	A	3	2000	30	74	120	0.99	3
	1 + 2	A	3	2000	79	197	320	0.90	4
	1	C	5	500	38	95	154	4.75	1
	2	C	5	500	31	77	125	7.00	3
	1 + 2	C	5	500	68	170	275	6.38	4
Gasification Complex	Hydro-carbons	A	3	2800	310	774	1255	0.73	
		C	5	200	654	1634	2650	2.55	
	(SO_2 Partic.)	A	3	2800	27	67	109	0.73	3
		C	5	200	57	123	200	2.55	6
Gasification Steam Plant		A	3	2800	50	117	190	0.90	4
		C	5	400	51	123	200	5.00	4

TABLE V-19

Maximum SO_2 and Hyrocarbon Concentrations Resulting From Inversion Breakup Fumigation

Plant	Unit(s)	Wind Speed (M/Sec)	Stability Class	Maximum SO_2 Concentrations 15 Min	Maximum SO_2 Concentrations 1 Hour	Distance of Maximum (KM)
Bridger	1 + 2 + 3 + 4	0.5	E	2,200*	550*- 275**	4.76
Colstrip	1 + 2	0.5	E	1,470	368 - 184	2.87
	3 + 4	0.5	E	1,820	455 - 228	4.29
	1 + 2 + 3 + 4	0.5	E	3,100	775 - 388	2.91
Gentleman	1 + 2	0.5	E	1,190	298 - 149	5.29
Olds	1	0.5	E	370	93 - 47	3.21
	2	0.5	E	460	115 - 58	5.15
	1 + 2	0.5	E	760	190 - 95	3.63
Naughton	1	0.5	E	580	145 - 73	1.65
	2	0.5	E	730	183 - 92	1.75
	3	0.5	E	700	175 - 88	2.46
	4 + 5	0.5	E	870	218 - 109	5.28
	1 + 2 + 3 + 4 + 5	0.5	E	2,100	525 - 263	3.00
Underwood	1 + 2	0.5	E	940	235 - 118	5.24
Wyodak	2	0.5	E	1,050	263 - 132	2.36
Young	1	0.5	E	1,140	285 - 143	2.16
	2	0.5	E	560	140 - 70	4.09
	1 + 2	0.5	E	1,480	370 - 185	2.50
Gasification Complex (Hydrocarbons)		0.5	E	10,100	2525 - 1263	1.13

* Upper limit was arrived at by essentially ignoring the effects of vertical wind shear.

** Lower limit is suggested to be a more realistic concentration estimate if vertical wind shear is significant.

FIGURE V-5

MAXIMUM AMBIENT SO2 CONCENTRATIONS
(PLANT CONTRIBUTION ONLY)

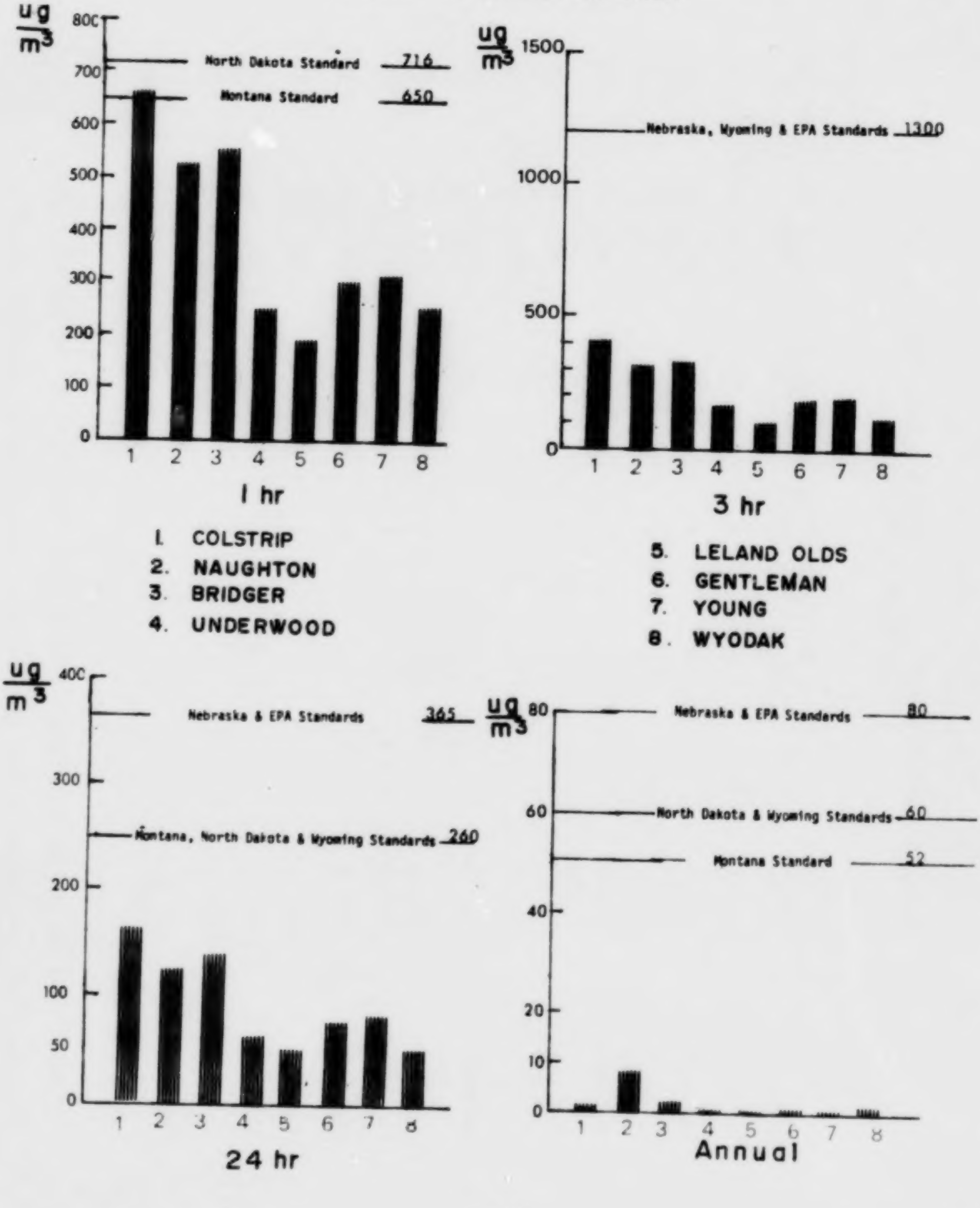


FIGURE V-6

MAXIMUM AMBIENT PARTICULATE CONCENTRATIONS

(PLANT CONTRIBUTION ONLY)

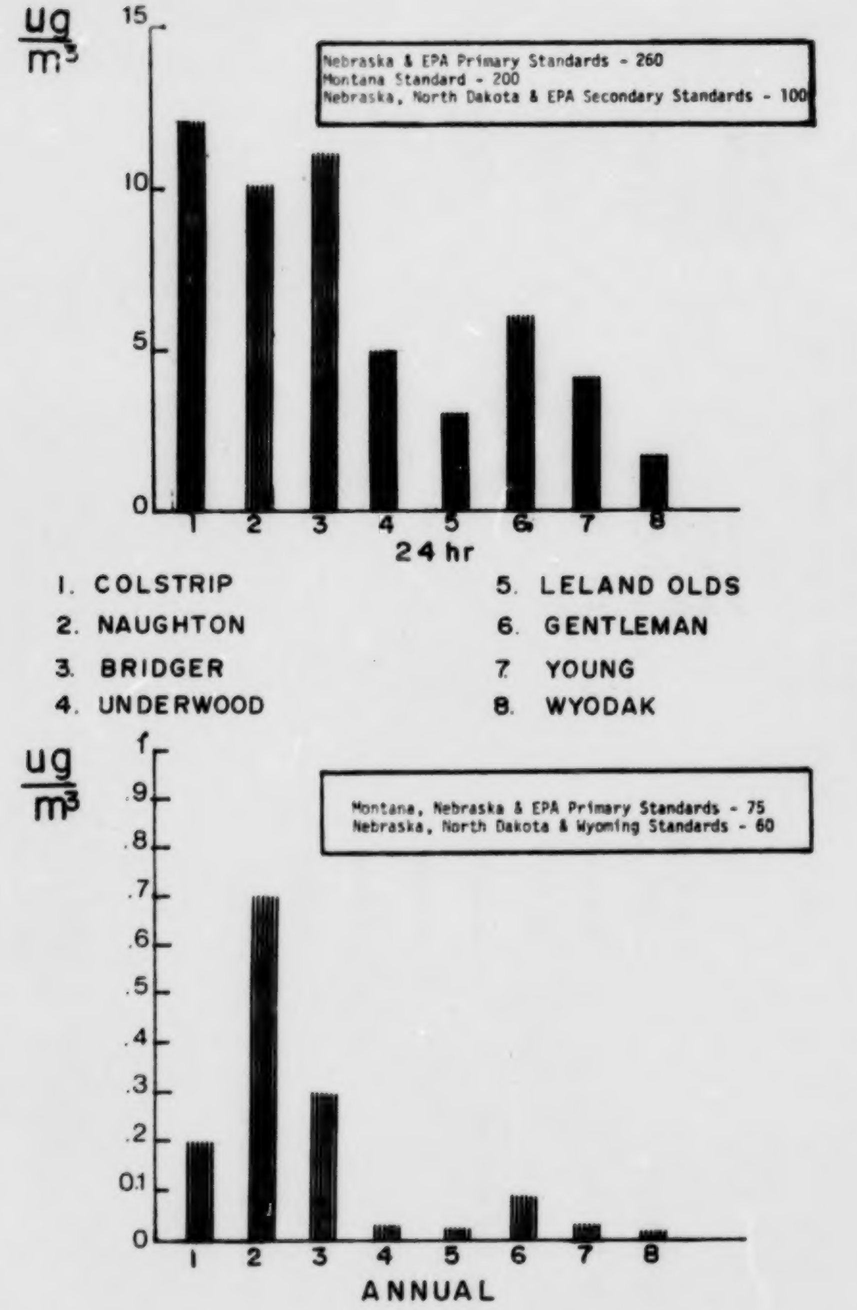


Table V-20

Maximum Colstrip Concentrations
Plant + Peak Background Contributions

Pollutant	Averaging Time	Maximum Background Concentrations* (ug/m^3)	Maximum Computed Plant Contribution (ug/m^3)	Total Air Quality Level (ug/m^3)
Particulates	Annual	15	.2	15.2
	24-Hour	127	12	139
Sulfur Dioxide	Annual	6	2	8
	24-Hour	37	164	201
	3-Hour	--	410	--
	1-Hour	--	665	--
Nitrogen Oxides	Annual	10	1	11

* Montana Power Company and Montana State Department of Health Data
Reported in: Colstrip Generation & Transmission Project:
Applicant's Environmental Analysis Report
Montana Power Co. (1974)

Table V-21

National Ambient Air Quality Standards for Selected Pollutants (ug/m^3)

Pollutant	Primary	Secondary	Averaging Time
Particulates	75	60**	Annual
	260*	150*	24-Hour
Sulfur Dioxide	80	--	Annual
	365*	--	24-Hour
	--	1300*	3-Hour
Nitrogen Oxides	100	100	Annual

* Not to be exceeded more than once/year.

** Guide to be used in assessing State implementation plans to achieve the 24-hour standard.

Table V-22

State Ambient Air Quality Standards
for Selected Pollutants ($\mu g/m^3$)

State	Pollutant	Standard	Averaging Time
Montana	Particulates	75	Annual
		200[1]	24-Hour
	SO_2	52.4 (.02 ppm)	Annual
		262 (.10 ppm)[2]	24-Hour
		655 (.25 ppm)[3]	1-Hour
Nebraska	Particulates	Same as National Ambient Air Quality Standards	
	SO_2		
	NO_x		
North Dakota	Particulates	60	Annual
		150[4]	24-Hour
	SO_2	60	Annual
		260[4]	24-Hour
		715[4]	1-Hour
	NO_x	100	Annual
		200[2]	1-Hour
Wyoming	Particulates	60	Annual
		150[4]	24-Hour
	SO_2	60	Annual
		260[4]	24-Hour
		1300[4]	3-Hour
	NO_x	100	Annual

1. Not to be exceeded more than 1% of time.
2. Not to be exceeded more than 1%/3 months.
3. Not to be exceeded more than once/4 days.
4. Not to be exceeded more than once/year.

pollutants are sufficiently below all applicable standards indicating that the combined plant and background levels will not exceed the annual standards for the three pollutants in question.

5.3.1.2 Short Term Impacts: 24-Hour Concentrations

Flat terrain estimates of 24-hour SO_2 and particulate concentrations have shown no violations of State or National ambient air standards. The maximum 24-hour SO_2 and particulate levels (including background) were computed to be 201 and 139 ug/m^3 respectively.

Terrain model estimates did indicate potential SO_2 air quality standard violations when plumes traveling through stable air impinge upon distant terrain. Site specific meteorological data have indicated that the meteorological condition used in the model (Table V-6) does not persist long enough to build up the predicted concentrations. Allowing time for the stable plume to travel to the distant terrain, a period of 8-9 hours of F stability would be required to produce air quality standard violations. The limited data available (12 months) indicated that the probability of such an occurrence is very small. Consequently, the terrain model results are unrealistic and have not been published. Additional data gathering efforts will assist in future reevaluations of this issue.

5.3.1.3 Short Term Impacts: 3-and 1-Hour Concentrations

Three-Hour SO_2 estimates for Colstrip were less than the Federal Secondary standard of 1300 ug/m^3. It is doubtful that the background SO_2 levels would be large enough to raise the maximum 3-hour plant contribution (410 ug/m^3) above the 1300 ug/m^3 level.

If there will be a problem of the Plant's meeting air quality standards, it appears that the 1-hour State standard (655 ug/m^3) would be the most vulnerable. Flat terrain estimates produced a maximum 1-hour plant concentration of 630 ug/m^3. The calculated value, (665 ug/m^3) as listed in Table V-18, was converted from sea level STP conditions to those conditions existing at the plant's elevation (3250 ft), for comparison to the State air quality standard. The background 1-hour SO_2 level is not available and when it is eventually combined with the plant contribution, the net result may cause a violation of the State standard. Additional upper atmosphere wind and temperature data is required at the plant site to assess the variation of wind with altitude and to determine how often these high 1-hour values might occur. This is needed because of the wording of the Montana regulation.

Results of fumigation calculations indicate possible violations of the State 1-hour standard. The predicted plant contributions to the 1-hour SO_2 concentration ranged between approximately 730 (insignificant vertical wind shear) and 370 ug/m^3 (significant vertical wind shear). The above two concentrations correspond to atmospheric conditions at plant altitude. It is difficult at this time to definitely predict the potential violation of the 1-hour concentration because of the uncertainty of the fumigation model and the unquantified amount of wind shear.

5.3.2. Nebraska: Gerald Gentleman Plant

Background air quality data for the Sutherland plant site is not available. It is therefore only possible to list the Gentleman Plant's contribution to the ambient pollutant loadings.

All calculated concentrations, for all averaging times considered, were by themselves less than the applicable standards (Table V-21 and V-22). The worst case estimates for particulates, NO_x and SO_2 are listed below:

TABLE V-23: Maximum Ground Level Concentrations:
Gentleman Plant

POLLUTANT	TIME PERIOD	MAXIMUM COMPUTED PLANT CONTRIBUTION (ug/m^3)
Particulates	Annual	0.08
	24-hour	6
SO_2	Annual	0.8
	24-hour	77
	3-hour	192
	1-hour	310
NO_x	Annual	0.6

The terrain in the vicinity of the plant suggested that elevated terrain modeling was not required since elevations varied by less than approximately 100 meters within a 40 km radius of the plant.

5.3.3 North Dakota Facilities

5.3.3.1 Leland Olds Plant

Modeling results indicate that the calculated plant concentrations by themselves, as summarized in the following table, are less than the State and National standards.

TABLE V-24: MAXIMUM GROUND LEVEL CONCENTRATIONS: LELAND OLDS -- ALL UNITS

POLLUTANT	TIME PERIOD	MAXIMUM CONCENTRATIONS (ug/m^3)
Particulates	Annual	0.03
	24-hour	3
SO_2	Annual	0.5
	24-hour	47
	3-hour	118
	1-hour	192
NO_x	Annual	0.3

However, the lack of plant site air quality data prevents an adequate test of compliance with standards. Extensive NGPRP air quality and meteorological data gathering in the Stanton area will provide a considerable amount of baseline data. The importance of comparing the existing air quality levels to the calculated plant contributions cannot be overstressed considering the present and projected future (see Section IV) energy related activity in this area of North Dakota. This is further illustrated by the results of the Underwood calculations.

5.3.3.2 Underwood Plant

The background air quality in the neighborhood of the plant plays a dominant role in determining Underwood's compliance with ambient air standards. Combined plant and background levels are summarized in Table V-25 for several pollutants and averaging times.

5.3.3.2.1 Long-Term Impacts

Ground level annual calculations of particulates, SO_2 and NO_x for the Underwood Plant were very small, less than 1 ug/m^3. The background particulate concentration is significant. With a value of 52.1 ug/m^3, this concentration is close to the National Secondary standard. For particulate matter and NO_x, the combined plant and background estimates fell beneath State and National levels. SO_2 background air quality data were not available.

5.3.3.2.2 Short Term Impacts: 24-Hour Concentrations

Unlimited and limited mixing calculations for particulates produced estimates small in comparison to the background levels (see Table V-25). Agricultural and construction activity in the plant area produced a 24-hour particulate background maximum of 384 ug/m^3, which is in excess of the National and North Dakota standards. The plant contribution was

Table V-25

Maximum Underwood Plant Concentrations
Plant + Peak Background Contributions

Pollutant	Averaging Time	Maximum Background Concentrations* (ug/m^3)	Maximum Computed Plant Contribution (ug/m^3)	Total Air Quality Level (ug/m^3)
Particulates	Annual	52.1	0.04	52.1
	24-Hour	384**	5	389
Sulfur Dioxide	Annual	--	0.4	--
	24-Hour	--	62	--
	3-Hour	--	154	--
	1-Hour	--	250	--
Nitrogen Oxides	Annual	7.0	0.4	7
	1-Hour	34.8	208	243

* Data reported in: Environmental Analysis for a North Dakota Power Supply Project for Cooperative Power Association & United Power Association. Burns & McDonnell (1973)

** High value attributed to agricultural and construction activity in the area.

estimated to be approximately 5 ug/m^3. Obviously, the combined contributions will also exceed the standards. The SO_2 maximum of 62 ug/m^3 was less than the most stringent 24-hour SO_2 standard (260 ug/m^3). Plume trapping calculations, using C stability, resulted in a maximum SO_2 24-hour concentration of 50 ug/m^3. 24-hour SO_2 background data were not available.

5.3.3.2.3 Short Term Impacts: 3- and 1-hour Concentrations

One hour violations were predicted for NO_x. The NO_x background of 34.8 ug/m^3 coupled with the model estimate (assuming unlimited mixing and A stability conditions) of 208 ug/m^3 yield a net 243 ug/m^3 which exceeds the North Dakota one hour standard of 20 ug/m^3 of which must not be exceeded more than 1% of the time every three months. It is noted that the NO_x plant contribution, by itself, exceeds the State standard. As in the Colstrip discussion, detailed site specific data are needed at the plant site to assess how often these conditions cause this high NO_x concentration in a three month period.

5.3.3.3 Milton Young Plant

Air quality impacts are summarized in Table V-26 using available background air quality data for the plant site. The only apparent violation is of the 1-hour NO_x standard. Computer models indicate a maximum 1-hour plant contribution of 230 ug/m^3. Baseline NO_x data is not available, and hence the total ambient pollutant level cannot be predicted.

The predicted ambient one hour SO_2 average is 530 ug/m^3 which may be compared to 715 ug/m^3 State standard. Three-hour, 24-hour and annual SO_2 levels are also less than the allowed values.

Particulate concentrations resulting from the plant were very low for both annual and 24-hour averaging times. The annual ambient particulate level is 52 ug/m^3, which is below the secondary standard of 60 ug/m^3. 24-hour background particulate levels were not available, and no estimate of the ambient concentration for this time period was made.

5.3.4 Wyoming Facilities

5.3.4.1 Jim Bridger Plant

Background air quality data at the plant site, as documented in the Final Environmental Impact Statement, is rather limited. The maximum annual particulate background is given as 40 ug/m^3, while SO_2 background values are just described as "low". Without comprehensive background information, it is only possible to list the plant's

Table V-26

Maximum Young Plant Concentrations
Plant + Peak Background Contributions

Pollutant	Averaging Time	Maximum Background Concentrations* (ug/m^3)	Maximum Computed Plant Contribution (ug/m^3)	Total Air Quality Level (ug/m^3)
Particulates	Annual	52	.03	52
	24-Hour	--	4	--
Sulfur Dioxide	Annual	25	.3	25.3
	24-Hour	70	79	149
	3-Hour	--	197	--
	1-Hour	210	320	530
Nitrogen Oxides	Annual	--	.3	--
	1-Hour	--	230	--

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* Data recorded in: Environmental Impact Analysis: Milton R. Young Electric Station Center Unit 2 for Minnkota Power Cooperative Inc., and Square Butte Electric Cooperative, Inc. (1973)

contribution to the ambient air quality, as in Table V-27: The concentrations shown are corrected to sea level STP conditions. Conversion of these numbers for comparison to State air quality standards to reflect the plant elevation would reduce the values shown by about 16 percent.

TABLE V-27: MAXIMUM GROUND LEVEL CONCENTRATIONS: JIM BRIDGER PLANT

POLLUTANT	AVERAGING TIME PERIOD	MAXIMUM COMPUTED PLANT CONTRIBUTION (ug/m^3)
Particulates	Annual	0.3
	24-Hour	11
SO_2	Annual	3.3
	24-Hour	137
	3-Hour	341
	1-Hour	553
NO_x	Annual	1.9

The estimated annual ambient particulate level at the plant is 40.3 ug/m^3 less than all applicable standards. The background accounts for most of the concentration (40 ug/m^3). Annual SO_2 and NO_x plant contributions were small.

Flat and elevated terrain computations were made to determine 24-hour particulate and SO_2 levels. Flat terrain estimates were generally an order of magnitude less than the corresponding ones made under the assumption of sloping terrain. Preliminary site specific data at the Bridger Plant indicate that the meteorological condition (F stability, SSE winds) used in the terrain model does not persist long enough to build up the predicted concentration. On the basis of these data, the likelihood of an occurrence of F stability and SSE winds for a 6-9 hour period appears extremely unlikely. Therefore, the terrain model predictions appear to be unrealistic and have not been published. Further evaluations of the importance of terrain will be made after additional data have been collected.

The 3-hour maximum SO_2 concentration was 341 ug/m^3 under A stability and unlimited mixing conditions, while the maximum 1-hour concentration was 553 ug/m^3 resulting from the above conditions. The fumigation case resulted in predicted concentrations of SO_2 ranging from 275 to 550 ug/m^3 for one hour.

5.3.4.2 Naughton Plant

Short term SO_2 background data has been collected at the plant site for a period of several months (Naughton Units 4 & 5, Applicant's Environmental Analysis (1973)). The maximum 1-hour SO_2 average during that period was 230 ug/m^3 (.089 ppm). Particulate and NO_x background data are not available.

5.3.4.2.1 Long Term Impacts

Maximum plant contributions to the ambient pollutant levels are given in Table V-28. As mentioned in the Jim Bridger Plant discussion, the values shown must be reduced by about 17 percent when comparing the predicted air quality concentrations to State standards.

TABLE V-28: MAXIMUM GROUND LEVEL CONCENTRATIONS
NAUGHTON PLANT (ALL UNITS)

POLLUTANT	AVERAGING TIME PERIOD	MAXIMUM COMPUTED PLANT CONTRIBUTION (ug/m^3)
Particulates	Annual	.7
	24-Hour	10
SO_2	Annual	68
	24-Hour	126
	3-Hour	315
	1-Hour	525
NO_x	Annual	6

An elevated terrain model of this plant was run to determine the effect that terrain within a 40 km radius of the plant might have on the concentrations. Results of an annual terrain model indicated a maximum concentration of 68 ug/m^3 (not including background) approximately 6 km NNW of the plant site. Correcting this value to the plant's elevation, as required by the Wyoming State regulations, yields a value of 57 ug/m^3 compared to the State standard of 60 ug/m^3. SO_2 background data added to this contribution may produce violations of the State annual SO_2 standard.

Annual flat terrain SO_2, particulate, and NO_x concentration estimates at the other seven power plants were low, and indicated that incorporating terrain effects at these sites would not produce concentrations in violation of any annual standard.

The annual NO_x concentration from the plant is 6 ug/m^3 assuming flat terrain. A terrain model calculation would have produced a maximum concentration of approximately 50 ug/m^3 which is half of the NAAQS.

Annual particulate concentrations, under sloping terrain conditions, would amount to only a few ug/m^3.

5.3.4.2.2 Short Term Impacts

As with the Bridger and Colstrip results, the terrain model predictions were felt to be unrealistic because the meteorological condition of F stability and S winds does not persist long enough to transport the plume to the elevated terrain and impinge there for the six hours required by the model.

Additional background data is required before further comparisons with standards can be made.

5.3.4.3 Wyodak Plant

Plant background air quality data was not available for analysis. As a result, Table V-29 only lists the model predictions for Wyodak. These values represent sea level STP conditions and must be reduced by 8 percent in order for a comparison to State standards to be made.

TABLE V-29: MAXIMUM GROUND LEVEL CONCENTRATIONS DUE TO WYODAK PLANT

POLLUTANT	AVERAGING TIME PERIOD	MAXIMUM COMPUTED PLANT CONTRIBUTION (ug/m^3)
Particulates	Annual	.1
	24-Hour	1.6
SO_2	Annual	1.3
	24-Hour	51
	3-Hour	123
	1-Hour	263
NO_x	Annual	.7

Several conclusions were reached from the Wyodak model runs. Terrain effects at the plant were judged not significant within a 38 km radius. The 24-hour terrain calculation produced a maximum concentration of 25% of that predicted by the worst case A stability estimates. Trapping calculations produced a contribution of 51 ug/m^3.

5.4 MODEL COAL GASIFICATION PLANT

5.4.1 Assumed Stack and Effluent Parameters

EPA emissions estimates were made for the gasification process. A typical gasification plant size of 250 million standard cubic feet of gas production per day was used. A steam generating plant with a 325 megawatt equivalent capacity was assumed. The plant is required to fulfill the steam requirements of the gasification step and the electrical requirements of the complex. These electrical requirements may be 60 megawatts. Compliance with the NSPS was assumed in order to calculate emissions from the steam generating plant associated with the gasification plant. Emissions from the gasification plant portion of the complex are not subject to any Federal emissions standards. Some states have promulgated gasification plant regulations. Thus, the emissions that were used represent an average value based upon the data available to the EPA.

A comment on the type and magnitude of hydrocarbon emissions to be expected from the gasification complex is in order. There is expected to be a significant amount of HC emissions from a gasification plant unless controls are installed. As is shown in our model predictions, the hydrocarbon air quality standard is expected to be violated under some meteorological conditions. Hydrocarbons are precursors of photochemical oxidant formation. The reactivity of the hydrocarbons plays a major part in the oxidant formation, however. Olefinic and highly substituted aromatics, i.e., unsaturated hydrocarbons, are extremely reactive while other hydrocarbons such as the paraffins are relatively inactive and probably don't contribute significantly in the oxidant formation. Table V-30 shows the relative reactivities of several types of hydrocarbons. It was observed that the hydrocarbon emissions from the gasification complex consist of methane, ethane and ethene. Only ethane and ethene emissions were used in the model air quality predictions. The composition of the total hydrocarbon emissions is shown below:

	Pounds/hour	Weight %
Methane	6,540	30
Ethane	5,450	25
Ethene	9,810	45
	21,800	100

A plant load factor of 100 percent was used in order to calculate emissions to be used as input to the model for estimating the short-term, i.e., 3-hour and 24-hour, air quality concentrations. Annual emissions based upon a plant load factor of 91 percent were used for input to the model in order to predict annual air quality concentrations.

Table V-30

Hydrocarbon Reactivity

	Relative Reactivity[1]	
	Altshuller and Cohen[2]	Haagen-Smit[3]
Methane	1.0	1.0
Ethane	3.0	1.0
Acetylene	10.0	2.5
Ethylene	30.0	10.0
Xylene	--	35.0
1,3 - Butadiene	--	60.0

1. Using CH_4 as 1.0.

2. International Journal of Air and Water Pollution; Altshuller and Cohen; October 1963.

3. Air Quality Criteria for Photochemical Oxidants; HEW; March 1970.

Table V-31

Summary of Point Source Modeling Input Data

1. Plant Hypothetical Gasification Plant

2. Location Northeastern Wyoming

3. Unit(s)	Gasification Complex	Associated Steam Plant
4. Size (MW)	250 MM SCFD	325 MW

5. Emissions (GM/SEC) Load Factor

	100%	91%	100%	91%
Particulates	18	16	43	38
Sulfur Dioxide	167	149	517	470
Nitrogen Oxides	27	24	301	274
Hydrocarbons	1923	1753		

6. Stack Data

Height (M)	91	121
Diameter (M)	1.6	3.8
Exit Temperature (°K)	552	400
Gas Exit Velocity (M/SEC)	27.4	27.4
Gas Volume Flow Rate (M^3/SEC)	57	311

7. Source of Wind Data Moorcroft, Wyoming STAR Program

The actual stack and effluent data used in making the dispersion estimates for the gasification complex and the associated steam plant appear in Table V-31.

Data supplied in recent environmental reports filed by companies planning the construction of coal gasification plants would indicate that control systems are being designed to minimize the HC emissions. A discussion of these techniques is found in Section VII of this report. If these techniques prove reliable, it is claimed that the HC emissions will be negligible and thus the estimated air quality concentrations indicated in Table V-32 are much too high.

5.4.2 Estimated Impact on Air Quality

The worst case estimates of pollutant concentrations resulting from a model gasification plant indicate a potentially severe air pollution problem. Summary Table V-32 illustrates the high reactive hydrocarbon concentrations for four averaging periods. The 3-hour value of 1,634 ug/m^3 is over ten times greater than the National HC 3-hour ambient air standard of 160 ug/m^3. The 1,634 ug/m^3 was calculated under the worst case condition of limited mixing (200-meter height) and C stability.

Fumigation concentrations (1-hour) were also extremely high. Concentrations in the range from 1263 to 2525 ug/m^3 were estimated for a 1-hour average.

Reactive hydrocarbons can combine with the NO_x plant emissions (154 ug/m^3 1-hour average) and sunlight to form photochemical oxidants.

Hydrocarbon emissions and resulting high ground level concentrations are a problem decision makers should not avoid. Terrain can substantially magnify these impacts as power plant calculations have already demonstrated.

5.5 SUMMARY COMMENTS ON MODELING RESULTS

Modeling predictions have indicated potential air quality standard violations. Several qualifications must be made in interpreting these results:

1. Sector-averaged results underestimate maximum concentrations, especially for small downwind distances and short averaging times.

2. Flat terrain gaussion models may predict concentrations within a factor of two or three of the actual value.

3. The elevated terrain model requires verification at plant sites in the Northern Great Plains.

Table V-32

Maximum Calculated Gasification Plant Concentrations Gasification Complex and Associated Steam Plant

Pollutant	Averaging Time	Gasification Complex Contribution (ug/m^3)	Steam Plant Contribution (ug/m^3)	Combined Contribution (ug/m^3)
Hydrocarbons	Annual	23	--	23
	24-Hour	654	--	654
	3-Hour	1634	--	1634
	1-Hour	2650	--	2650
NO_x	Annual	0.3	.7	1
	1-Hour	37	117	154
SO_2	Annual	1.9	1.5	3.4
	24-Hour	57	51	108
	3-Hour	142	123	265
	1-Hour	230	200	430
Particulates	Annual	.2	.1	.3
	24-Hour	6	4	10

Background air quality plays an important role in defining the significance of the power plants' contributions. The modeling results have stressed the importance of having background air quality data in order to assess the total air quality picture.

The shorter term standards (1-hour) will probably be the most stringent standards a large plant will have to meet. Fumigation can produce significant short term concentrations and the fumigation inversion breakup conditions should be addressed in future power plant environmental assessments.

The proposed regulations are indicated in Table III-3 of this report. A comparison of the modeling results for the eight power plants and the hypothetical gasification plant with the proposed standards would show that a zone 1 classification would restrict all plants and that a zone 2 classification would restrict the Colstrip, Bridger, Naughton, and hypothetical gasification plants.

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SECTION VI

COAL CONVERSION ALTERNATIVES

Coal in the NGP may be utilized in several different ways. It may be used directly to fuel power generating boilers or industrial boilers. It may be converted to synthetic natural gas (SNG) via one of the several gasification processes under development, or it may be liquified to a synthetic crude oil and other petroleum products. A fourth possible alternative is to clean the coal via some cleaning process, followed by direct firing, gasification, or liquefaction. These four alternatives are discussed in some detail below. The second alternative, i.e., coal gasification, is the subject of a special report to be published via the NGPRP in early 1975.

6.1 DIRECT FIRING

Coal in the NGP is primarily of the sub-bituminous and lignite nature, with heating values ranging from about 6,000 to 10,000 BTU per pound. The properties and quantities of impurities in the coal are of major importance in the selection of steam generating equipment. No boiler will perform equally well with all types of coal; there is a certain set of conditions for which optimum performance in a boiler is achieved. Ash softening temperature, ash content, sulfur content, slag viscosity, coal grindability, and moisture content are included in the factors that specify the type of boiler to be used in a given installation. There are three basic types of furnace designs in existence today, 1) pulverized, 2) cyclone and 3) stoker. However, the stoker design is probably a thing of the past, especially for large utility boilers. There are many overfire and underfire stokers in existence, but due to efficiency, capacity, and environmental considerations, no new units are being designed. The pulverized furnace enjoys the largest share of the market today because of its adaptability to operate on a wide range coal. The cyclone furnace has a special advantage when burning low grade coals such as lignite. These types of furnace design are discussed in detail below.

6.1.1 Pulverized Furnace

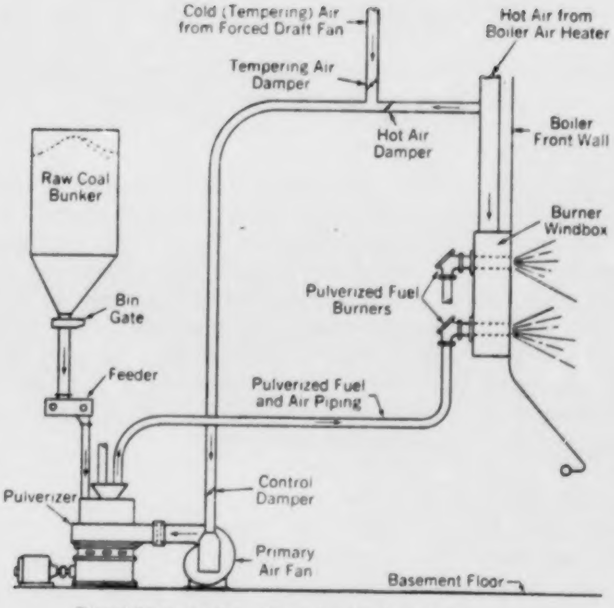
Pulverized coal firing was first introduced in the 1920's and represented a major advance in operating flexibility, efficiency and economy over the stoker fired units. A well designed unit may be designed for a net plant heat rate (NPHR) of about 9,000 BTU per kilowatt-hour on a 2,400 psi steam cycle. This represents a plant overall efficiency of about 38 percent. Many units, however, are still being designed for a NPHR of 10,500 BTU per kwh, or an efficiency of 32 percent.

The main components of a pulverized coal system are: 1) raw coal feeder; 2) source to supply hot primary air to the pulverizer for drying the coal; 3) pulverizer fan; 4) pulverizer; 5) coal and air conveying lines; and 6) burners. A simple diagram showing these components is shown in Figure VI-1. The coal qualities which are most important in the selection and design of a pulverized furnace include grindability, rank, moisture, volatile matter and ash. It is, of course, desirable to have low moisture and low ash coal but the furnaces are designed for the type of coal that is anticipated to be used.

Two types of systems have been used for processing, distributing, and burning the pulverized coal -- the bin system and the direct-firing system. The direct-firing system is used in almost all new systems designed today. The bin system was used until pulverizer equipment could be designed to operate reliably on a continuous basis. Two types of direct firing methods exist -- the pressure type and the suction type. The difference essentially lies in the position of the fan in relation to the pulverizer. The most common location is on the pulverizer inlet rather than on the outlet; hence, the pressure type is more common. Pulverizers are generally designed to operate through a load range of about 3 to 1. The pulverizer is usually designed to produce a coal feed to the burners with a product fineness of 70 percent through a 200 mesh sieve (200 mesh = 74 micron size particles). There are about 7 different types of pulverizers with no one type dominating the field. The pulverizers are usually classified according to speed:

1. Medium speed (75-225 rpm)
    a) Ball and race
    b) Roll and race
        i) Standard
        ii) Bowl mill
2. Slow speed (<75 rpm)
    a) Ball and race
    b) Roll and race
    c) Tube mill
3. High speed (>225 rpm)
    a) Impact mill

Air is supplied to the pulverized coal system at two and sometimes three locations. About 20 percent (volume) is supplied to the pulverizer in order to convey the coal to the burner. This air is called primary air. A conveyance velocity in the pipe is normally about 4,000 feet per


Cold (Tempering) Air from Forced Draft Fan
Hot Air from Boiler Air Heater
Tempering Air Damper
Hot Air Damper
Boiler Front Wall
Raw Coal Bunker
Burner Windbox
Pulverized Fuel Burners
Bin Gate
Feeder
Pulverized Fuel and Air Piping
Control Damper
Pulverizer
Primary Air Fan
Basement Floor

Direct-firing system for pulverized coal.

FIGURE VI-1

minute. The remaining 80 percent (volume) of air is supplied at the burner and initiates combustion. This air is called secondary air. In some cases, a portion of the secondary air is supplied to burner points at the top of the combustion zone in order to cool the flame temperature and still complete combustion. This technique is effective in reducing nitrogen oxide emissions and is called overfire air firing. The air supplied to the pulverizer and to the burners is generally preheated by the hot flue gases coming from the furnace and after the superheater. The preheated air is usually about 650° F.

6.1.2 Cyclone Furnaces

The cyclone furnace has made a significant contribution to the steam power industry by improving combustion and furnace performance and by permitting the economic utilization of low rank and grade coal.

The first commercial cyclone furnace boiler was installed in 1944 in Illinois. There are now about 700 cyclone furnaces in operation in the United States.

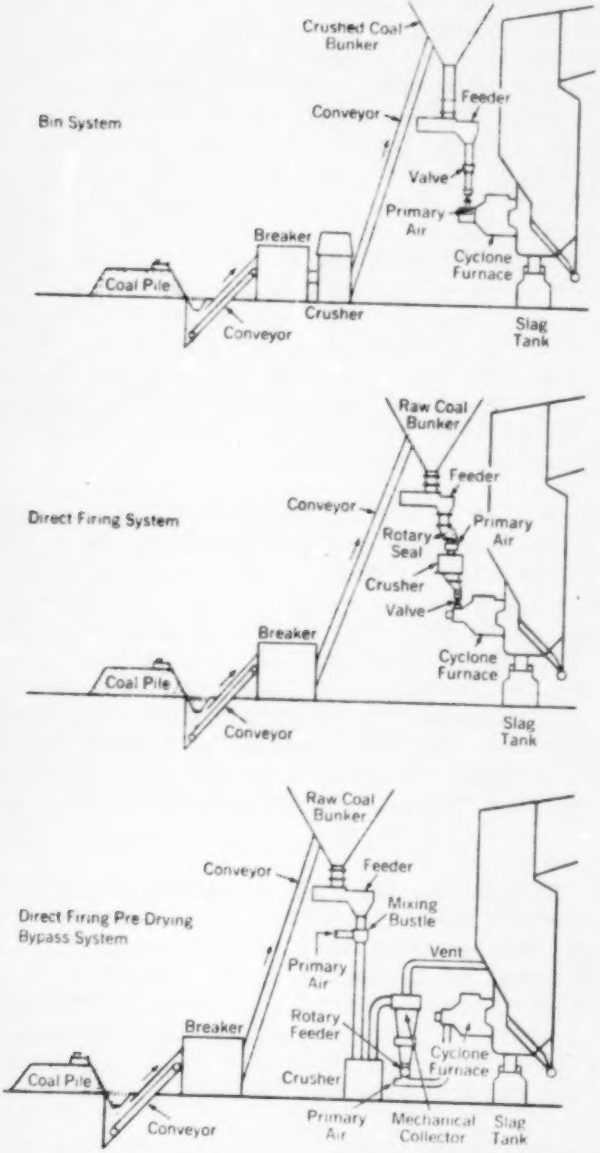
The specific coal characteristics that dictate the design of a cyclone furnace are volatile matter, ash content, ash type, and ash viscosity. The ash viscosity is the critical factor in design. Coal having a slag viscosity of 250 poise at 2600° F or lower is capable of being successfully and economically burned in a cyclone furnace. However, the ash analysis must not indicate excessive formation of iron pyrites. The ratio of Fe_2O_3 to $(CaO + MgO)$ should not exceed 25 (by weight) in the ash for coal of a S content less than three percent. Higher ratios will indicate excessive iron and iron oxide formation which can affect slagging tendencies and have corrosion effects.

Volatility of the coal should be greater than 15 percent (AF) to achieve the required combustion rate. Maximum ash and moisture content should be 25 and 20 percent (AF) respectively. The moisture content may be somewhat higher (as high as 40 percent) for lignite coal. Ash content should not be below six percent in order to achieve adequate slag formation.

With lignite and sub-bituminous coal, cyclone firing enjoys the same advantages as pulverized firing over stoker firing, plus:

1. Reduction in fly ash content in the flue gases
2. Fuel preparation cost savings
3. Reduction in furnace size

Primary components of the cyclone furnace system are: 1) coal conveyors; 2) coal crusher; 3) coal storage; 4) coal feeder; and 5) cyclone furnace. Three systems for coal preparation and feeding are illustrated in Figure VI-2.


Bin System
Crushed Coal Bunker
Conveyor
Feeder
Valve
Primary Air
Breaker
Cyclone Furnace
Coal Pile
Crusher
Conveyor
Slag Tank
Direct Firing System
Raw Coal Bunker
Feeder
Conveyor
Rotary Seal
Primary Air
Crusher
Valve
Breaker
Cyclone Furnace
Coal Pile
Conveyor
Slag Tank
Raw Coal Bunker
Conveyor
Feeder
Direct Firing Pre Drying Bypass System
Mixing Bustle
Primary Air
Vent
Rotary Feeder
Breaker
Cyclone Furnace
Coal Pile
Crusher
Conveyor
Primary Air
Mechanical Collector
Slag Tank

Bin, direct-firing, and direct-firing pre-drying bypass systems for coal preparation and feeding to the Cyclone Furnace (schematic).

FIGURE VI-2

Principle of operation of the cyclone furnace boiler is based upon crushing the coal, feeding it to the furnace by gravity, and combusting it with primary, secondary and tertiary air. There are several major differences between the cyclone furnace and the pulverized furnace. These will be pointed out as the principles of operation are discussed. The cyclone furnace is a water-cooled horizontal cylinder in which extremely high heat release rates and combustion zone temperatures are achieved. Coal is conveyed to a simple crusher where it is crushed to a product fineness of 95 percent passing through a four mesh sieve (four mesh will pass a 4760 micron particle). Recall that pulverized coal is much finer (70 percent through 200 mesh). Thus, there is a substantial power savings because of less severe grinding and crushing operations. After crushing, coal is discharged to a rotating distributor which assures uniform feed rate to the furnace. About 20 percent of the combustion air enters the burner tangentially and imparts a whirling motion to the incoming coal. Secondary air with a velocity of about 300 feet per second is also introduced tangentially at the roof of the main barrel of the cyclone and imparts a further whirling or centrifugal action to the coal particles. A small amount of air (about five percent) is admitted at the center of the burner. This is known as tertiary air.

Temperatures in excess of 3,000° F. and heat release rates of up to 800,000 BTU per ft^3 furnace per hour are developed in the cyclone furnace. These temperatures are sufficiently high to melt the ash into a liquid slag. This slag forms a layer on the walls of the cyclone and is subsequently drained off at the slag tap to the slag tank. Incoming coal particles are thrown against the wall of the cyclone by the centrifugal force of the incoming primary air and are further combusted by the tangentially induced secondary air. Thus, the required air is supplied quickly (lowering the time required for combustion), and the products of combustion are rapidly removed. These gaseous products of combustion are discharged from the small cyclone chamber through the cyclone throat into the large boiler furnace.

By this method of combustion, the fuel is burned quickly and completely in the small cyclone chamber, and the boiler furnace is used only for cooling the flue gases. Because the incoming coal is thrown against the liquid slag and then combusted, most of the ash remains entrained in the slag. Thus, potential fly ash emissions are much less than from a pulverized furnace. Because the coal is so fine in a pulverized furnace, after combustion in the furnace chamber the small ash particles tend to remain in suspension in the flue gas and pass out through the boiler.

The boiler furnace may be designed in two arrangements -- single wall firing and opposite wall firing. Slag handling is similar to that of a pulverized wet bottom furnace and is usually done on a batch basis.

As previously mentioned, power requirements for crushing are lower for the cyclone than the pulverized system. The forced draft fan power requirements are higher, however, with air pressure drops of 20 to 40 inches of H_2O compared to 2 to 10 inches H_2O for the pulverized burner.

Table VI-1 shows power requirements for various grades of coal for cyclone and pulverized furnaces. It shows that from a power requirement standpoint it is more economical to use a cyclone furnace when the coal heat content is less than 10,000 BTU per pound (AF). The data below show a relative comparison of a pulverized furnace and a cyclone furnace, each equipped with a 95 percent efficient electrostatic precipitator. These data would necessarily assume equal size precipitators and/or equal particle size distribution of fly ash to be meaningful.

	Relative Ash Quantities	
	Cyclone	Pulverized
Incoming Ash	100	100
Furnace Bottom Ash	70	20
Precipitator Catch	28.5	76
Ash to Stack	1.5	4

The cyclone furnace is generally started up with oil. This will tend to minimize fly ash emissions during the slag build-up phase in the cyclone chamber. A cyclone furnace may provide continuous operation from about a half to a full load range with no burner servicing.

6.1.3 Stokers

Mechanical stokers were developed early in the history of combustion in the steam boiler. There are four basic types: 1) spreader; 2) underfeed; 3) water cooled vibrating grate; and 4) chain grate and travelling grate. Steam generating units with a capacity of less than 100,000 pounds of steam per hour (12,800 kw) may still be designed to utilize the stoker concept. In larger plants pulverized for cyclone furnaces are more economical. They are also more environmentally acceptable. For these reasons, no further discussion of stokers is deemed necessary.

6.2 COAL GASIFICATION

Due to lack of production of sufficient quantities of natural gas and low sulfur crude oil, plus the requirement of state and Federal emission regulations, there has been a frenzy of activity in the development of processes to produce synthetic natural gas (SNG) recently. Commercial processes exist today to convert crude oil or naphtha into SNG. Some 27 plants representing a capacity of nearly 50 billion scfd have been announced or are in operation or construction. However, because of the vast resources and reserves of coal in the United States, a key to energy self-sufficiency in the United States (from the supply standpoint) lies in the successful and economical conversion of coal into SNG. Possibly of equal importance is the development and commercial installation of processes to convert coal into low BTU fuel gas to be used in utility and industrial boilers.

Table VI-1

Auxillary Power Requirements

Coal Type	Coal BTU/LB (AF)	Grindability	kwhr/BTU input
Pulverized			
Bituminous	14,000	100	1.2
	13,000	65	1.35
	12,600	58	1.45
	10,000	55	1.65
Sub-Bituminous	9,600	50	1.75
Lignite	6,800	50	2.05
Cyclone			
All coals	---	--	1.65

Stated very simply, coal gasification is a process which breaks coal down into its chemical components; i.e., C, H, N, O, etc., and then recombines the C and H to form methane (CH_4). Methane is the prevalent component (over 90 volume percent) of natural gas. Hence, the term synthetic natural gas is derived. In the gasification process when the coal is initially broken down into its components, there exists only about one hydrogen atom per every carbon atom. Methane, however, needs four hydrogen atoms for every atom of carbon, i.e., CH_4. Therefore, water (H_2O) is added in the form of steam to supply the additional hydrogen atoms. A more detailed discussion of the reactions follows.

The chemical reactions which take place in the gasification process for both the high BTU (SNG) and the low BTU process are shown in Table VI-2. A process diagram of the high BTU process (950 BTU/scf) is presented in Figure VI-3. The low BTU process (150-400 BTU/scf) is almost identical with the exception of the methanation step. This step is shown as reaction 5 in Table VI-2.

An association of the reactions for the high BTU process in Table VI-2, with the process diagram shown as Figure VI-3, provides the following description. Reaction 1 is the devolatilization reaction in which the light hydrocarbons, i.e., those easily volatilized, are driven off as a result of the hot gases leaving the gasification zone of the gasifier coming into contact with coal falling countercurrently into the gasifier. Most processes under development today utilize a two-stage gasifier in which the first stage serves as the devolatization zone and the second stage functions as the gasification zone. The gasification step, which is reaction 2, requires a significant amount of heat input. A portion of this heat input is provided by the hydrogasification step (reaction 4), which is highly exothermic.

The hydrogen consumed in reaction 4 is produced in part by reaction 3, the water gas reaction which produces CO_2 and free hydrogen. Reactions 2, 3 and 4 generally are designed to take place in a single vessel; i.e., the gasification portion of the gasifier.

Air or oxygen may be supplied in order to supply supplemental heat via the exothermic reaction shown in reaction 4 of the low BTU process. At this point in the gasification scheme, the crude gas leaves the gasifier with a heat content of 150 to 400 BTU per scf, depending upon whether air or oxygen is added. If only air is added, the heat content will be about 150 BTU/scf. The composition of the crude gas is shown in Table VI-3. In order to increase the heat content of the crude gas equivalent to that of natural gas, the catalytic methanation step must be employed. This step is shown as reaction 5 and results in a gas composition similar to that shown in Table VI-3 for the high BTU gas. Prior to methanation, however, the gas must be purified and its composition altered as depicted in Figure VI-3. The alteration of the gas composition is required in order to have the proper H_2/CO ratio in the gas going to the methanation step. As shown in reaction 5, three moles of H_2 are required

Table VI-2

Coal Gasification Reactions

High BTU Process

(1) Coal $\dashrightarrow$ $CH_4 + C$ (exothermic)

(2) $C + H_2O_{(v)} \dashrightarrow CO + H_2$ (endothermic)

(3) $CO + H_2O_{(v)} \dashrightarrow CO_2 + H_2$ (exothermic)

(4) $C + 2H_2 \dashrightarrow CH_4$ (exothermic)

(5) $3H_2 + CO \dashrightarrow CH_4 + H_2O$ (exothermic)

Low BTU Process

(1) Coal $\dashrightarrow$ $CH_4 + C$ (exothermic)

(2) $C + H_2O_{(v)} \dashrightarrow CO + H_2$ (endothermic)

(3) $CO + H_2O_{(v)} \dashrightarrow CO_2 + H_2$ (exothermic)

(4) $C + 1/2\ O_2 \dashrightarrow CO$ (exothermic)

Table VI-3

Gas Composition

Volume Percent

	Low BTU gas	High BTU gas
H_2	38	4
H_2S, COS	< 1	--
CO	20	--
CO_2	28	2
CH_4	11	93
C_2H_6	1	--
N_2	< 1	1
TOTAL	100	100
BTU/SCF	300	900

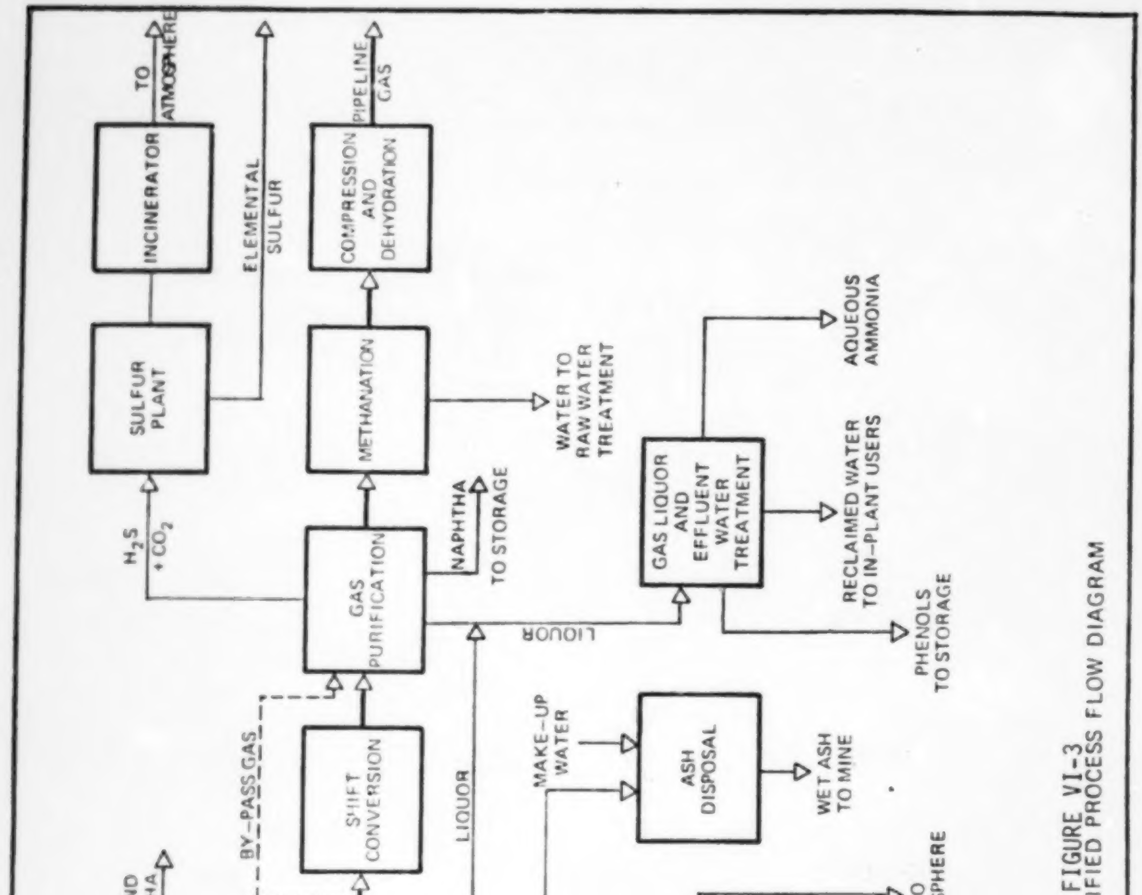

AIR
OXYGEN PLANT
NITROGEN
OXYGEN
FEED COAL
COAL PREPARATION
OXYGEN BLOWN COAL GASIFIERS
STEAM
QUENCH WATER
TAR SEPARATION
TAR AND NAPHTHA
BY-PASS GAS
SHIFT CONVERSION
LIQUOR
GAS PURIFICATION
H2S + CO2
NAPHTHA TO STORAGE
SULFUR PLANT
ELEMENTAL SULFUR
INCINERATOR
TO ATMOSPHERE
METHANATION
WATER TO RAW WATER TREATMENT
COMPRESSION AND DEHYDRATION
PIPELINE GAS
AIR
AIR BLOWN COAL GASIFIERS
ASH
STEAM
FUEL GAS
ASH
MAKE-UP WATER
ASH DISPOSAL
WET ASH TO MINE
LIQUOR
GAS LIQUOR AND EFFLUENT WATER TREATMENT
AQUEOUS AMMONIA
RECLAIMED WATER TO IN-PLANT USERS
PHENOLS TO STORAGE
STEAM
POWER AND STEAM PLANT
POWER TO PLANT USERS
TO ATMOSPHERE
RAW WATER
RAW WATER TREATMENT AND STORAGE
TREATED WATER
MAKE-UP WATER TO IN-PLANT USERS

FIGURE VI-3
SIMPLIFIED PROCESS FLOW DIAGRAM

Table VI-4

Gas Components Heating Values

	BTU/scf
N_2	--
H_2S	621
CO_2	--
CO	321
H_2	274
CH_4	911
C_2H_4	1499
C_2H_6	1631

for every mole of CO in order for the reaction to proceed completely to the formation of CH_4. The H_2/CO mole ratio of the crude gas is typically about two to one. Therefore, the H_2 content relative to the CO content must be increased. This is done catalytically on a portion of the gas stream. The amount of the portion treated is determined by the H_2/CO ratio in the crude gas leaving the gasifier. Normally, about 50 percent of the gases from the gasifier are fed to the shift convertor with the resultant gas stream having a H_2/CO ratio of about eight to one. Both gas streams are purified to eliminate as much CO_2 and S compounds as possible, then are combined and fed to the methanator. The H_2/CO ratio at this point in the process is normally designed to be about 3.5 to 1, to insure a complete reaction.

The methanation step is performed catalytically. As is seen by Table VI-3, the CH_4 concentration is increased from about 11 volume percent to about 93 percent. This raises the heat content of the gas from about 300 to about 900 BTU per scf.

There is limited commercial application of the coal gasification process. Table VI-5 lists the present low BTU process applications practiced in the world today. Several firms in the U.S. are making use of low BTU gasifiers in order to insure a constant supply of gas for their industrial operations. There are no high BTU process commercial plants, but there is extensive pilot plant development and commercial applications planning going on. Table VI-6 and Table VI-7 provide some insight to these activities.

Economics of the coal gasification plants indicated required capital expenditures of around 500 million dollars for an average 250 MMSCFD plant and offsite facilities. It appears that the cost of SNG from the plant will be in the neighborhood of $1 per thousand scf. This compares to present prices of 40¢ to 60¢ per thousand scf. Only through no price controls placed upon the sale of SNG increased prices of natural gas and/or the creation of a government subsidy to the gasification plant owners does it appear that the production of SNG will be an economically viable process.

An assessment of the potential environmental effect of a typical coal gasification plant is found in other sections of this work group report (see VII and IX). The coal gasification process is the subject of a special report to be published in conjunction with the interim NGPRP report. It will provide a detailed discussion of the history, chemistry, economics and environmental impact of the gasification process. In-situ gasification will also be discussed in the special report. Only the "conventional" processes have been discussed in this section because of the limited development of the in-situ process.

Table VI-5

Commercial Applications

Low BTU Process

	Process	Description	Pressure	Efficiency
1.	Wellman-Galusha	Fixed bed	1 atm.	82%
2.	Winkler	Fluidized bed	1 atm.	66%
3.	Koppers	Fixed bed	1 atm.	67%
4.	Lurgi	Fixed bed	20 atm.	82%

TABLE VI-6

COAL GASIFICATION SUMMARY

Process	Gasifier Type	Research Begun	Pilot Work Begun	Commercial Development	Gasifier Pressure
1. Lurgi (Lurgi)	Fixed Bed	?	?	14 plants since 1930	445 psig
2. Synthane (USBM)	Fluidized Bed	1963	late 1974 Bruceton, Pa. (75 tpd)	--	1000 psig
3. HYGAS (Institute of Gas Technology)	Fluidized Bed	1943	1971 Chicago, Ill. (75 tpd)	--	1000 psig
4. CO_2 Acceptor (Consolidated Coal Co.)	Fluidized Bed	1950	1972 Rapid City, S.D. (40 tpd)	--	150 psig
5. Bigas (Bituminous Coal Research)	Fluidized Bed	?	scheduled? Homer City, Pa. (120 tpd)	--	1000 psig
6. Hydrogasification (USBM)	Fluidized Bed	?	none	--	1000 psig
7. COED (FMC)	Fluidized Bed	1962	1970 Princeton, N.J. (36 tpd)	--	10 psig
8. Molten Carbonate (M.W. Kellogg)	Fluidized Bed	?	--	--	1200 psig

Table VI-7

Announced Commercial Installations

	Company	Location	Process	Plant Capacity
1.	Transwestern Coal Gasification Co., Pacific Coal Gasification Co., and Western Gasification Co.	near Burnham, New Mexico	Lurgi	250×10^6 scfd
2.	El Paso Natural Gas Co.	near Burnham, New Mexico	Lurgi	250×10^6 scfd
3.	Panhandle Eastern Pipeline Co., and Peabody Coal Co.	near Douglas, Wyoming	Lurgi	288×10^6 scfd
4.	Michigan-Wisconsin Pipeline Co.	near Beulah, North Dakota	Lurgi	250×10^6 scfd

6.3 COAL LIQUEFACTION

Depletion of domestic crude oil reserves, decreased exploration, increased consumption, decreased Middle East supplies, desire for energy self-sufficiency, and the impact of environmental actions are factors which point to the need to develop a larger supply of crude oil and petroleum products in the United States. One way to accomplish this is through the successful large-scale development of the coal liquefaction process. This process simply involves the conversion of coal into a synthetic oil which has a desired property of containing only minimal amounts of ash and sulfur. It would seem that there would be a significant amount of research and development work in this area, but more emphasis appears to be on coal gasification. Only one commercial liquefaction plant exists in the world today, that being the Sasol plant in South Africa. It is owned and operated by the South African Coal, Oil and Gas Corporation. A few pilot plants are operational in the United States and are discussed later.

The hydrogen to carbon ratio in natural gas, oil, and coal is 4.0, 1.1 and 0.9 respectively. This indicates a minimum of hydrogenation required to produce oil from coal; i.e., to increase the H/C ratio from 0.9 to 1.1. This fact would indicate a less severe processing requirement and should indicate a more economical process (4) than for coal gasification which must increase the H/C ratio from 0.9 to 4.0.

Production of snythetic oil from coal may proceed via one of the four process options shown below:

1. Production of a H_2/CO mixture followed by catalytic synthesis.
2. Solvent refining with minimum hydrogenation.
3. Pressure hydrogenation.
4. Staged pyrolysis.

The first process option above is the well known Fischer-Tropsch synthesis. It is the basis of operation of the Sasol plant described earlier. Basically, the process utilizes a lurgi gasifier to gasify the incoming coal. The resultant gas is purified and then catalytically reformed with steam and oxygen. The reformer effluent gases are cooled to condense the liquid hydrocarbon products. Gasoline and fuel oils are produced in this manner. A yield of about 3,700 barrels per day of gasoline and 400 barrels per day of fuel oil is obtained at the Sasol plant from a coal feed rate of about 2,000 tons per day.

A pilot plant utilizing the chemistry of the second process option above has recently been constructed by a Gulf Oil Company subsidiary, the Pittsburgh and Midway Coal and Mining Company. Solvent refining of coal to produce a low ash, low S oil requires a minimum degree of hydrogenation. The solvent refined coal (SRC) process pilot plant is located near Fort Lewis, Washington, and is designed to process 50 tons per day of coal. In the SRC process, coal is pulverized to about <1/8 inch (#6 mesh) and is slurried with an anthracene oil solvent. About 30 to 40 pounds of hydrogen per ton of coal is added to the slurry. The slurry is then heated, pressurized, and filtered. The filtrate is vacuum flashed to remove the solvent. The liquid product may be kept at elevated temperatures to preserve its liquid state or cooled so that it forms solid particles or lumps. During the process, almost all of the ash, all of the pyritic sulfur, and about half of the organic sulfur are claimed to be removed from the coal. The product has the properties shown below. This is based upon a high sulfur bituminous coal.

SRC Product Properties

Heat Content	16,000 BTU/pound
Ash Content	<0.1 percent
Sulfur Content	<1 percent

The third process option, pressure hydrogenation, is the subject of two processes -- the Consol process and the H-coal process. Consolidation Coal Company developed a process (later to be called Project Gasoline) under the funding of the Office of Coal Research (OCR) which resulted in the construction of a pilot plant in 1967. Operation of the pilot plant has been changed to the production of a synthetic crude oil rather than gasoline. The H-coal process developed by Hydrocarbon Research, Inc. (HRI) under funding by the OCR produces light oils and a char oil bottoms product. This bottoms product may be used as a fuel or be further processed to achieve a 100 percent conversion of solids to liquid hydrocarbon. The Consol process and the H-coal process use essentially the same process scheme with H-coal operating at slightly lower pressure. Coal is crushed to 8 mesh or finer, slurried with a hydrogen donor solvent, and heated to above 800° F. About half of the coal undergoes dissolution and cracking during this step. The resultant solution is separated (solids from liquid) with the liquid stream being sent to a catalytic reactor. The reactor cracks the high molecular weight hydrocarbons to the gasoline and fuel oil range. The solids from the separation step may be sent to a carbonization unit, where severe cracking of the solids takes place, producing more liquid hydrocarbon distillates and a residual char. An economic evaluation of this process placed the break-even point at between $4 and $5 per barrel of oil, based upon a three barrel per ton yield from the process and using coal at about $1.50 per ton. (1)

Atlantic Richfield Company (ARCO) and the FMC Corporation have developed coal to oil processes based upon the fourth process option mentioned earlier, that of multistaged fluidized bed pyrolysis. Project

Seacoke (ARCO) and COED (FMC) produce a mixture of oil and gas from coal. The fluidized bed pyrolysis process involves the crushing and pulverizing of coal (93% through 14 mesh for ARCO; < 200 mesh for FMC), followed by preheating for drying purposes to about 300° F. This heated coal is then pneumatically conveyed to the first of a series of fluidized bed reactors (ARCO has 5, FMC has 4). The temperature in the reactors increases from about 600° F. in the first reactor to about 1600° F. in the final reactor. Volatiles escape overhead from the reactor, and residual char flows by gravity to the next reactor in series. Volatiles from all of the reactors are combined and cooled to about 200° F. This results in a gas-liquid hydrocarbon mixture which is subsequently separated and purified. The oil thus produced may be further processed via hydrogenation, distillation, or flash evaporation in order to produce a myriad of petroleum feedstocks and/or products. The product yield of a pilot plant operation, using the COED process, is shown below. Gas quality is about 500 BTU per scf.

COED Product Yield

	Weight Percent	Volumetric Yield/Ton
Char	56	--
Oil	19	1.2 barrels
Gas	17	9000 scf

6.4 COAL CLEANING

The first step in the utilization of coal, whether it be by direct firing, gasification, or liquefaction, must necessarily be cleaning to some extent. Most often this cleaning is simply the removal of some of the ash and extraneous material present. However, some chemical cleaning processes are being developed to remove some of the sulfur in the coal prior to combustion or gasification.

Because of the lowering of coal quality in recent years, the need for coal cleaning has increased. This lowering of quality has come about because of 1) depletion of high quality coal seams, 2) increased usage of continuous mining machines, and 3) increased strip and auger mining. Economic incentives for coal cleaning include lower transporation charges, decreased storage requirements, and increased boiler efficiency and life due to decreased ash deposition on heating surfaces. Some sulfur removal is experienced through normal cleaning, but the sulfur removal processes labeled as "coal washing" are discussed later.

The degree of ash reduction resulting from cleaning cannot be generalized due to the types of ash present in the coal. Ash may be classified as inherent and removable. Ash forming mineral matter organically combined, i.e., that portion that existed in the plants from which coal was formed, is considered as inherent material and cannot be removed through a cleaning process. Extraneous mineral matter which is removable usually consists of slate, shale, sandstone or limestone. This material may have been deposited in the coal formation by foreign material settling into the formation or by water which penetrated the formation and left crystalline deposits in the cracks or cleavages. Inherent mineral matter usually contributes no more than about 2 percent of the total ash content of the coal as mined.

Cleaning the coal of ash is done by one of the four principal methods shown below.

1. Cleaning at the mine
2. Mechanical cleaning
3. Froth flotation
4. Gravity concentration

Cleaning at the mine is no longer a widespread practice. Due to increased usage of continuous mining machines, the miner has little control over the extraneous mineral matter which is collected along with the coal. In the past the miner would hand sort the coal from the ash forming impurities.

Mechanical cleaning of coal utilizes the differences in physical dimensions of coal and impurities as a means of separation. Slate and shale normally fracture into thin slabs, but coal fractures into cubes. Shaking tables and screens allow the impurities to pass through thin slots while retaining the coal.

Froth flotation separates impurities from coal in a liquid media. This technique has been practiced in the ore industry for years. Coal is crushed and ground so that it will pass a 48 mesh screen. The coal particles are fed to an agitated water bath where a given amount of air and surface tension promoting reagents are added. A surface froth forms and the coal particles are selectively attached to the bubbles. The heavier pyrite, shale and slate particles remain dispersed in the water and are subsequently separated. The coal particles attached to the bubbles flow over a weir and are collected.

Removal of impurities in coal by gravity concentration takes advantage of the difference in the specific gravity of coal and its impurities. The list below illustrates these differences. Commercial

Specific Gravity of Coal and Impurities

	Specific Gravity
Bituminous Coal	1.12 - 1.35
Bone Coal	1.35 - 1.7
Shale	2.0 - 2.6
Clay	1.8 - 2.2
Pyrite	4.8 - 5.2

processes may be classified as either wet or dry with about 95 percent of the processes today using wet methods. Almost half of the wet processes use jigs as the separation equipment. A jig consists of a screen upon which the coal rests with water sprays located above and below the screen. The upward and downward flow of water is alternated in pulses. The upward pulse tends to fluidize the bed of coal and the downward stroke rids the coal of its impurities. The dense media method is a second type of gravity concentration and accounts for about 30 percent of all wet processes. With this method coal is immersed in a liquid medium of a specific gravity between the coal and the impurities. Hence the coal floats and the impurities sink. The medium is usually a suspension of fine sand or magnetite in water. This method is known as the float-and-sink method. A third gravity concentration method which accounts for about 15 percent of the wet processes uses washing or concentrating tables. A suspension of fine coal in water flows across a table which oscillates at right angles to the direction of flow. The heavy particles, i.e., the impurities, settle to the bottom and are trapped by riffles. The lighter coal particles remain in suspension in the water. The remaining 5 percent of the wet processes employ use of classifiers, launders, and other flotation methods. The dry method of gravity concentration is similar in principle to the dense media method in the wet process. The difference is that the coal is suspended in an air rather than water in the dry process.

Sulfur in coal is of three forms - pyritic, organic and sulfate. The sulfate form is usually less than 1 percent (wt) of the total sulfur and therefore not significant. The distribution of pyritic and organic sulfur varies depending upon location of the coal bed and the sulfur content of the coal. It appears that for coal with sulfur content greater than about 1.5 percent (wt) the organic sulfur may make up only about 20 percent of the total sulfur. For coal of less than 1.0 wt. percent sulfur, the organic portion may be as much as 80 percent of the total sulfur content. For detailed analyses see the work group B report coal analyses. Current chemical processes can remove most of the pyritic sulfur but only a very small portion of the organic sulfur. Coal washing takes on the same characteristics of the dense media method described earlier. Sulfur removal may be enhanced by grinding the coal electrohydraulically or by adding solvents to the medium which form a chemical complex with the pyritic or organic sulfur and subsequently are separated from the coal. Several research efforts have been published regarding the chemical and physical removal of sulfur prior to combustion (11) (12) (13).

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SECTION VII

CONTROL TECHNOLOGY

The control of air pollutants at their source is a key guiding principle of environmental regulatory agencies. This principle has been mandated at the Federal level in wording contained in the 1970 Clean Air Act, as amended. Because of increased plant sizes, increased number of plants, more stringent emission regulations, and the demand for "cleaner air", significant pressure has been placed upon manufacturers of pollution control equipment to provide more efficient collection devices. Millions of dollars have been poured into research and development work in this field. Also, millions of dollars have been expended by the utilities industry for installation and operation of these devices. We have not yet, however, won the technology war. Many problems still exist which must be solved in order for the collection devices to operate properly and provide the degree of control that is required.

A discussion of the techniques and equipment used to control particulate matter, sulfur oxides, hydrocarbons, nitrogen oxides, carbon monoxide, and some trace elements is embodied in this section of the report. Although a degree of overlap of pollutant control exists for some equipment, such as the wet scrubber, most equipment or processes are designed specifically for one type of pollutant. With this in mind a discussion of control techniques for each pollutant follows. This discussion will focus upon applications pertinent to the fuel conversion industry and is meant to be an overview. Volumes and textbooks have been written on a single aspect of the control process. A special report will be issued during FY 75 via the NGPRP which will go into further detail on some of the equipment discussed in this report.

7.1 PARTICULATE MATTER

Particulate matter has been defined (1) as any material existing as a solid or liquid in the atmosphere or in a stack gas stream. Concerning the fuel conversion industry, we are most concerned with the finely divided particles of ash entrained in flue gases arising from the combustion of fuel. It is this fly ash which equipment is designed to collect. The equipment may consist of one of the following major types...

1. Settling chamber
2. Centrifugal collector
3. Electrostatic precipitator
4. Wet scrubber
5. Fabric filter

The wet scrubber and to some extent the fabric filter may be adapted to achieve some degree of SO_2 control. These adaptations will be discussed in section 7.2. Only the principles pertaining to particulate matter will be discussed in this section.

7.1.1 Settling Chamber

This method of particulate collection utilizes the force of gravity on a particle to achieve collection. These devices are capable of collecting only the large particles and have relatively low efficiencies (typically < 40 percent). Large space requirements and low collection efficiencies are disadvantages offset by simple design and operation. The chamber is simply a large box-type piece of equipment with baffles and trays (optional) in the inside of the box. A schematic is shown below in figure VII-1.

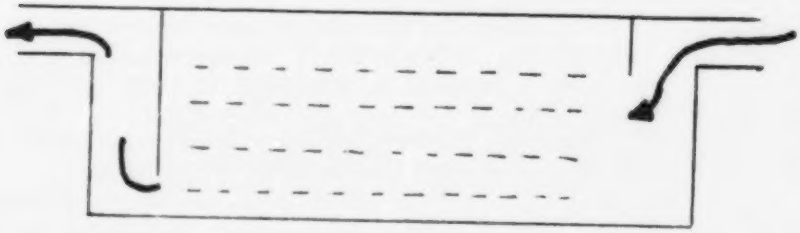


Figure VII-1

Settling Chamber-multitray

A dust particle falls under the force of gravity and achieves a constant terminal velocity which is dependent upon the size, shape, and other physical properties of the particle. The velocity of the gas entering the chamber is decreased via baffles so that the particles may settle out. Practical considerations usually limit collection of particles to those greater than about 43 microns. Gas velocity through a chamber is usually on the order of 1 to 10 feet per second.

Settling chambers, if used, are used only as a pre-cleaner to remove the large particles and agglomerated particles. Chambers are not a common control device and will not be in the fuel conversion industry. If a pre-cleaner is used, a centrifugal collector will be used because of its increased efficiency and most often its slightly decreased cost.

7.1.2 Centrifugal Collector

Dry centrifugal collectors, of which cyclones are the most common, utilize the centrifugal force created by a spinning gas stream to separate particulate matter from the carrier gas. The spinning motion is imparted to the gas stream by a tangential gas inlet, vanes or a fan.

Dust particles by virtue of their inertia move outward to the separator wall and fall downward into a collection hopper. Gravitational and frictional drag forces also act on dust particles, thus contributing to collection. Centrifugal force, however, is the major factor in determining collection efficiency.

Centrifugal collectors fall into the classification shown below.

1. Conventional reverse-flow cyclone
    a. Tangential inlet
    b. Axial inlet
2. Straight-through-flow cyclone
3. Impeller collectors

The conventional reverse flow cyclone may be designed for inlet gases to enter tangentially or axially to the cyclone body. The gases flow in a helical vortex fashion to the bottom of the cyclone in an outer core and reverse their flow through an inner core to the top of the cyclone. Hence, the name - reverse flow cyclone. Dust particles entrained in the flue gases are thrown by centrifugal force against the side walls and subsequently drop to the bottom of the cyclone and are removed. Collection efficiency of this cyclone is influenced by the diameter of the cyclone and the length of the cone.

The straight-through-flow collector consists of a cylindrical collector with swirl vanes located near the inlet. These vanes impart a swirling motion to the gases with the dust particles being forced against the side walls due to the centrifugal force. This type of collector is usually used only as a precleaner because of rather low efficiency. Low pressure drop and simple operation are advantages. The impeller collector is a dynamic type of cyclone in that gases enter the throat of the collector perpendicular to a fan blade shaped impeller (similar idea to that of a windmill). The dust particles are thrown through an annular slot to a collector and the cleaned gases are emitted from the outlet duct.

Collection efficiency of cyclones may expect to range anywhere from 50 to 90 percent depending upon, among other things, gas inlet velocity, particle size distribution, cyclone pressure drop, and cyclone dimensions. A high efficiency cyclone will collect 95 to 99 percent (weight) of incoming particles and have a cut size of about 3 microns.(1) Pressure drop in a high efficiency collector may be as much as 8 inches of H_2O. A bank of cyclones arranged in parallel is sometimes used in power plants and is commonly called a mechanical precipitator.

7.1.3 Electrostatic Precipitators

The high voltage electrostatic precipitator (ESP) is used at more large power plant installations than any other type of high efficiency particulate matter collector. A total of 741 installations including 1331 ESPs had been placed in operation by 1969 in the power plant industry. This represented installations on about 70 percent of the total generating capacity in the U.S. ESP units are being designed today to collect 98 to 99.5 percent by weight of the particulate matter emitted from a power plant. Depending of course upon the heat and ash content of coal being combusted, this efficiency is needed to meet the NSPS.

Collection of the particulate matter in an ESP entails three basic steps....

1. Electrical charging of the suspended matter
2. Collection of the charged matter on a grounded surface
3. Removal of the collected material

Dust particles are charged and passed through an electric field where electrical forces cause the particle to migrate toward a collection surface which is grounded. Particle charging is accomplished by means of a high voltage direct current corona. Corona, in this sense of the word, is a gas discharge phenomenon associated with the ionization of gas molecules by electron collisions in regions of high electric field strength. A non uniform electric field is generated by the use of a small diameter ($<$ 1/8 inch) wire as one electrode and a plate or cylinder as the other electrode. Application of high voltage to these electrodes results in an extremely high electric field near the wire. The corona process is initiated by the presence of electrons (supplied by natural radiation, photoionization, or thermal ionization) in the high electric field near the electrode wire. These electrons are accelerated to high velocities, impact with gas molecules, and create free electrons. This starts an electron "avalanche" process and continues throughout the electric field as long as the field is strong enough to provide the electrons enough energy for collisions and hence, ionization. The negative ions created in this corona process bombard the incoming dust particles and create a negatively charged dust particle which then migrates toward the grounded collecting surface.

The electrical force acting upon the charged particle must overcome gravitational, inertial, and viscous drag forces acting upon the particle. In a matter of milliseconds the particle reaches a terminal velocity in which the electrical and viscous drag forces become equal. This terminal velocity is called the migration velocity and is a key parameter in the design of an ESP. The collection efficiency of an ESP is related to the migration velocity in the classic Deutsch-Anderson equation shown below.

$$E = 1 - e^{-(Aw/V_g)}$$

where E = ESP collection efficiency
A = ESP collection area, ft^2
w = migration velocity, ft/min
V_g = gas volume, ft^3/min

The parameter w is an effective migration velocity and only relates to the probability of capture of a single particle. Thus it is a measure of performance of an ESP. At least two of the major ESP manufacturers disagree with the application of the Deutsch Anderson equation.

The second aspect of particulate matter collection, i.e., that of collection upon a surface, should briefly be discussed. Adhesive, cohesive and electrical forces must be sufficient to resist any counter electrical forces and gas stream action that would cause reentrainment of the dust particles in the gas stream. The electrical forces which are related to current density and dust resistivity, also affect the force required for removal of the dust layer formed on the collector electrode. Discussion of the importance of dust resistivity will be covered later in this section.

The final phase of the ESP particulate matter collection process involves that of the removal of the collected material. This aspect of the ESP may be classified as either the wet or dry method. The wet method consists of flowing a liquid down the collection electrode to wash the dust layer into a collection hopper at the base of the ESP. The dry method employs a technique known as rapping. In this procedure the collecting surface is mechanically shaken by means of a hammer, or rod, or some vibration imparting a force against the surface. Dust is dislodged and falls into a collection hopper at the base of the ESP. Because of the potential for dust reentrainment during this process, only small sections of the ESP are cleaned at once. The cleaning of the entire ESP is accomplished by means of alternating this rapping of each section. This is known as the rapping cycle.

Dust is usually removed from the collection hopper by pneumatic means and a sluice system. This collected dust then represents a solid waste disposal problem and may be taken care of by disposal at the mine, particularly if the plant is a mine mouth fuel conversion facility.

Dust resistivity and gas conditioning are two topics particularly important to the collection of fly ash emanating from the combustion of a low sulfur coal. Resistivity is a measurement or indication of the rate at which the charge leaks away from the dust particles once they are collected. An expression of this process is conductivity. Two distinct types of conduction take place about the particle. The first type, conduction by free electrons within the particle, depends upon the electron activation energy and the temperature of the operation. Most metallic oxides and sulfates have low activation energies in the 300 to 400°F range (normal operating temperature of an ESP) so that this type of conduction is low. At temperatures above 500°F the activation energies are high, making this type of conduction the primary mechanism for particles losing their charge. The second type of conduction is called surface conduction and relates to the conduction taking place over the surface of the particle. This conduction occurs due to absorption of moisture or other chemicals, such as H_2SO_4, onto the surface of the particle. Particle surface conductivity increases with decreasing temperature.

If particle resistivity is high, i.e., greater than about 2×10^{10} ohm-cm, the conductivity of the dust layer will be low and the charge will not leak off. This causes the electric field to exceed the breakdown strength in localized areas. High current densities exist and excessive sparking and formation of back or reverse corona will occur. Consequently, the voltage and hence the corona current must be reduced, which results in decreased particle charging and subsequently a lower ESP collection efficiency. Two basic approaches have been followed in order to keep dust resistivity below 2×10^{10} ohm-cm -- 1) gas conditioning and 2) temperature variation.

It has been found that fly ash resulting from the combustion of coal containing greater than 1 percent sulfur has a resistivity of less than 2×10^{10} ohm-cm. Thus, concern lies solely on the collection of particles resulting from combustion of low sulfur coal. It is theorized that some of the sulfur in the coal goes to sulfur trioxide (SO_3), which in turn adsorbs onto the dust particle surface. This increases the surface conductivity as described earlier. In order to enhance or increase this surface conductivity, some utilities have used an injection of anhydrous SO_3 into the gas stream before the ESP. It has been found that injection of SO_3 in order to achieve up to 40 ppm concentration in the ESP inlet gas stream was required to achieve successful particle collection. The SO_3 is called a conditioning agent, since it conditions the dust particle for increased conductivity via the adsorption phenomenon.

The second approach to lower resistivity has been to operate the ESP at temperatures above or below the normal 300°F operating temperature. It may be seen by figure VII-2 that it is in the 300°F temperature range that resistivity is a maximum, i.e., about 3×10^{11} ohm-cm for a low sulfur ($<$ 1 percent) coal fly ash. A lowering of gas temperature to about 250°F via dilution air or increased air heater space results in resistivities in an acceptable range. The potential of increased corrosion and/or fouling has caused utilities to shy away from this approach in some instances. Instead they have gone to design and operation of an ESP ahead of the air heater. The temperatures experienced at this location are in the 600 to 800°F range, which results in low resistivities as shown in figure VII-2. Successful operation of this technique has been experienced by at least three utility companies - Consolidated Edison of New York, Duke Power Co. and Public Service of Colorado. Principal design differences of the hot side ESP parameters are lower specific collection areas (230-400 vs. 400-700 ft^2/1000 acfm) than the cold side ESP if resistivity is a problem and a resultant higher cost by 2 to 3 times.

7.1.4 Wet Scrubbers

The application of wet scrubbers at power plant installations is becoming more widespread due to 1) attractiveness of combined particulate

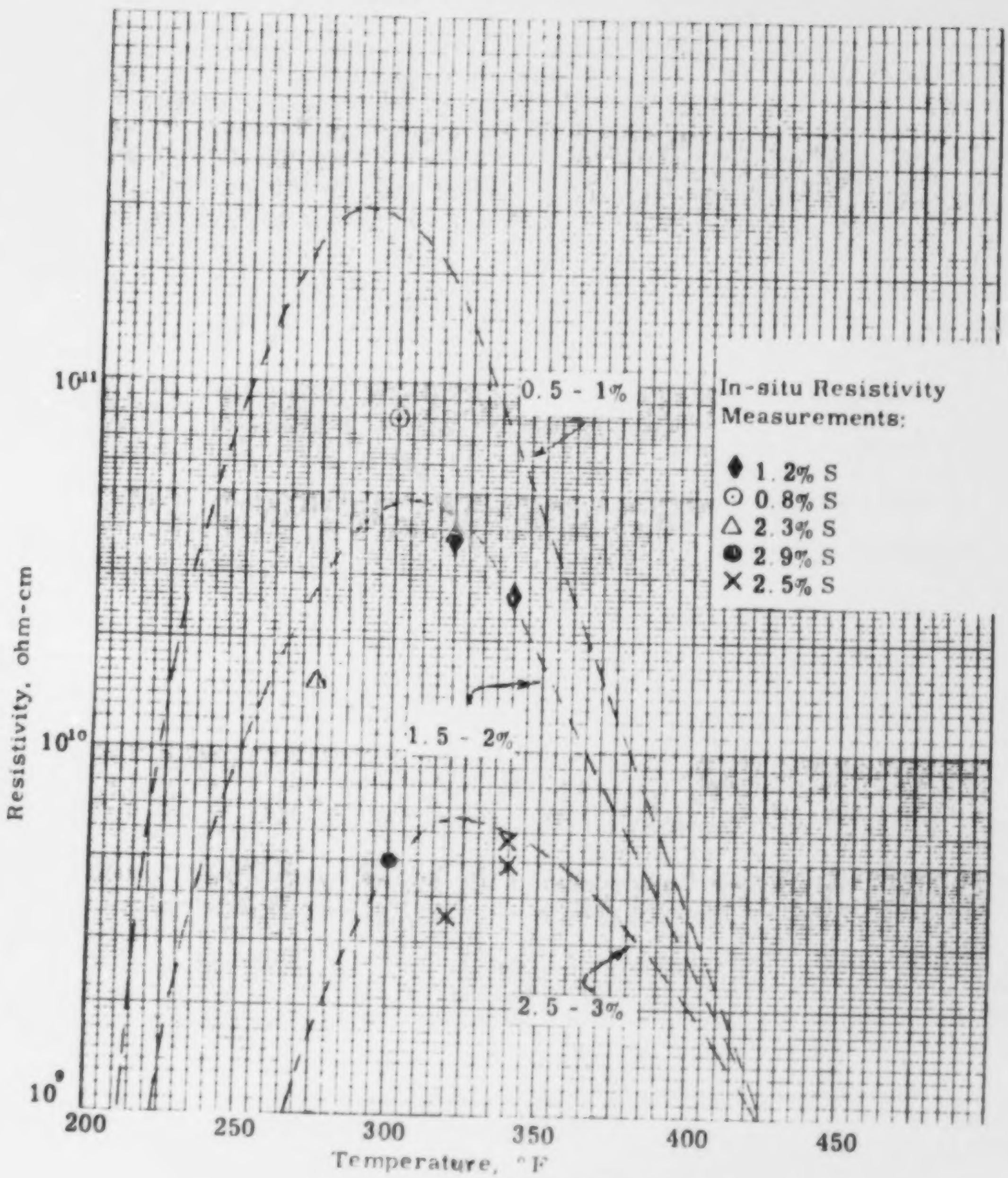


Figure VII-2

Trends in Resistivity of Fly Ash with Variations in Flue Gas Temperature and Coal Sulfur Content.

and SO_2 control, and 2) the resistivity problems encountered when firing low sulfur coal. Design of wet scrubbers is mandated by the type of collection desired. Some scrubbers are designed primarily to achieve good particle collection, other scrubbers are designed to provide good mass transfer capability, i.e., collection of gaseous pollutants, while still others are designed for a combination of particle and gaseous pollutant removal. There exist a vast number of scrubber types, designs, and manufacturers; more so for scrubbers than for electrostatic precipitators and fabric filters. It is possible, however, to categorize most of the scrubbers into the ten classifications shown below:

1. Plate
2. Massive Packing
3. Fibrous Packing
4. Pre-formed spray
5. Gas-atomized spray
6. Centrifugal
7. Baffle and secondary flow
8. Impingement
9. Mechanically aided
10. Moving bed

Some of these are more dominant in the fuel conversion facilities and therefore will be discussed in greater detail. Application and adaptation of some of these scrubbers to SO_2 control will be covered in section 7.2 of this report.

Regardless of the design of the scrubber the principal mechanisms by which particulate matter is collected are the same. The forces which bring the particles into contact with the liquid droplets are listed and defined below.

1. Interception. Interception occurs when particles are carried by a gas in streamlines around an obstacle at distances of less than the radius of the particle.

2. Gravitational Force. Gravitational force causes a particle, as it passes an obstacle, to fall from the streamline and settle on the surface of the obstacle.

3. Impingement. Impingement occurs when an object, placed in the path of a particle-laden gas stream, causes the gas to flow around

the obstacle. Larger particles, however, tend to continue in a straight path because of inertia and may impinge on the obstacle and be collected. (The impingement target efficiency is represented by the ratio of the cross-sectional area of the liquid droplets to the area of the gas stream cleared of particles.)

4. Diffusion. Diffusion results from molecular collisions and, except for submicron particles, plays little part in separation of particles from a gas stream.

5. Electrostatic Forces. Electrostatic forces result when particles and liquid droplets become electrically charged. An electrical charge may be induced by flame ionization or friction, or by the presence of charged matter. Electrostatic forces may affect collection efficiency significantly.

6. Thermal Gradients. Thermal gradients are important to the removal of matter from a particle-laden gas stream because particulate matter will move from a hot area to a cold area. The motion is caused by unequal gas molecular collision energy on the surfaces of the hot and cold sides of the particle, and is directly proportional to the temperature gradient.

Following is a discussion of the ten scrubber types.

The plate scrubber is a vertical tower with perforated plates or trays inside. Gas and liquid usually flow in a countercurrent manner with gases entering at the bottom of the tower. This type of scrubber provides excellent gas-liquid contact and, therefore, is well suited for both particle and gaseous pollutant removal. Disadvantages are possible tray plugging and moderately high pressure drop.

The massive packing scrubber is an excellent device for mass transfer operations and somewhat suitable for particle removal. Chief disadvantage lies in handling large inlet grain loadings and the associated pluggage of the bed. Liquid is introduced in a countercurrent fashion to gases rising through a packed bed of packings, such as Raschig rings, Berl saddles, Intalox saddles, etc.

The fiber bed scrubber is similar to the packed tower with the difference primarily being that this scrubber is usually horizontal with gases impacting upon an arrangement of filters. These filters, constructed of spun glass or fiberglass, are continuously wetted. Moderate collection efficiency and large space requirement are disadvantages of the system.

Pre-formed spray scrubbers utilize spray nozzles to atomize an incoming liquid which subsequently capture particles or gaseous pollutants on the droplets. The degree of atomization is a function of the nozzle type and the pressure supplied to the liquid. Spray towers are capable of good mass transfer and particle collection. Also, they enjoy low pressure drop and moderately low cost. The ejector venturi is a scrubber of this type and is capable of good particle collection, but has limited mass transfer capability due to its inherent cocurrent flow. In some scrubber applications the venturi is followed up by the cyclonic spray tower in order to achieve high particle and gaseous pollutant collection efficiency. This scheme shall be discussed further in section 7.2.

The gas atomized spray scrubber uses a moving gas stream to atomize a scrubbing liquid. This concept differs from that of the pre-formed spray scrubber in that pressure in this case is supplied to the gas stream rather than the liquid stream. High gas velocities (200 - 400 feet/second) are required. The flooded disk scrubber and venturi scrubber are two commercial applications in widespread use. Advantages of this type scrubber include high collection of sub-micron particles and flexibility of operation (through adjustment of liquid flow rate or gas velocity). Disadvantages include limited mass transfer capability due to concurrent flow, and high pressure drop, on the order of 10 to 15 inches H_2O.

A centrifugal scrubber may resemble a cyclone with the additional aspect of the introduction of a liquid at the cyclone inlet. Mass transfer capability is limited and collection efficiency decreases rapidly for particles less than a few microns. Pressure drop is on the order of 3 to 8 inches H_2O.

Baffle type scrubbers are similar to multitray settling chambers with the additional feature of introducing liquid in the form of a spray at the gas inlet. Collection of particles is limited to large particles. Collection of gaseous pollutants is low due to limited gas-liquid contact. Low pressure drop (1 to 3 in. H_2O) is an advantage.

Impingement scrubbers force incoming gases to skim over a liquid surface. Baffles are used to deflect the gases onto the liquid surface. Some degree of liquid atomization occurs as the gases impact the liquid. Collection is usually limited to particles larger than several microns in diameter. Little gaseous pollutant removal is realized. Low collection efficiency and moderate pressure drop (up to 20 inches H_2O) are disadvantages of this type of scrubber.

Mechanically aided scrubbers use a motor driven impeller submerged in a liquid bath to atomize the liquid. Gases enter perpendicular to the impeller and come into contact with the liquid droplets. Good particle collection efficiency, low water consumption, and low space requirements are offset by extremely high operating costs. Mass transfer capabilities are limited due to the low amount of liquid available for gas liquid contact.

Moving bed scrubbers provide a zone of mobile packing, usually of plastic glass or marble spheres, where gas and liquid can mix. A cylindrical shell similar to that of the packed tower is used to hold the spheres. Gas and liquid flow countercurrent and gas velocities are sufficient to keep the spheres in a fluidized state resulting in good turbulence. Good mass transfer capabilities and high particle collection efficiencies are realized with this type of scrubber. Several stages of beds are usually provided. This type of scrubber has been employed at several fuel conversion facilities and appears to enjoy successful operation.

7.1.5 Fabric Filters

One of the oldest and most dependable methods for removal of solid particulate matter from a gas stream is by filtration through a fabric media. The fabric filter is capable of extremely high collection efficiencies for small particles, even those as small as 0.5 microns. Dust bearing gases are passed through a fabric in such a manner that the dust particles are retained on the fabric and the cleaned gas passes through the filter and out of the baghouse. The baghouse is the structure in which the fabric filter hangs. The filters are usually bags of a tubular shape. Figure VII-3 shows a typical simple fabric filter baghouse. There may be thousands of bags in a large baghouse.

7.1.5.1 Collection Mechanism

Particle collection is achieved in this control technique by the combined effects of the mechanisms shown below.

1. Interception

2. Impaction

3. Diffusion

4. Electrostatic

5. Sieving

Air flow in a baghouse is usually laminar. Direct interception occurs when a dust particle is in the fluid streamline which collides with a filament in the fabric filter. Because the fluid streamlines necessarily bend around a fabric filter filament as shown below, particles of a certain size and mass will follow this streamline. Other larger particles, because of their mass, do not follow the

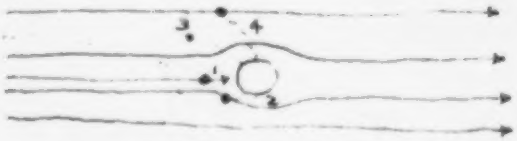


Figure VII-4

Fabric Filter Particle Collection Mechanisms

1. Interception
2. Impaction
3. Diffusion
4. Electrostatic

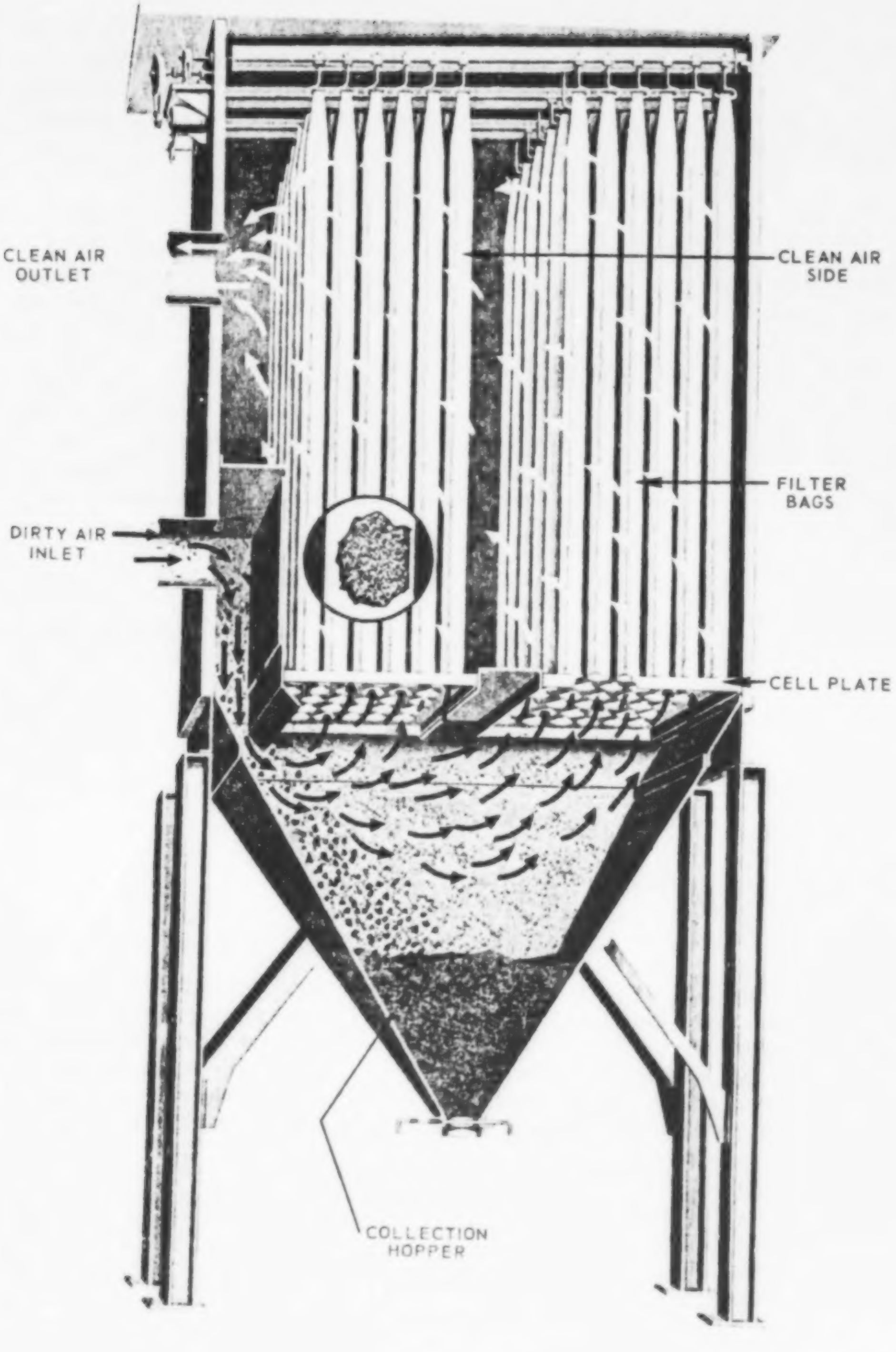

CLEAN AIR OUTLET
CLEAN AIR SIDE
FILTER BAGS
DIRTY AIR INLET
CELL PLATE
COLLECTION HOPPER

Figure VII-3

Typical simple fabric filter baghouse design.

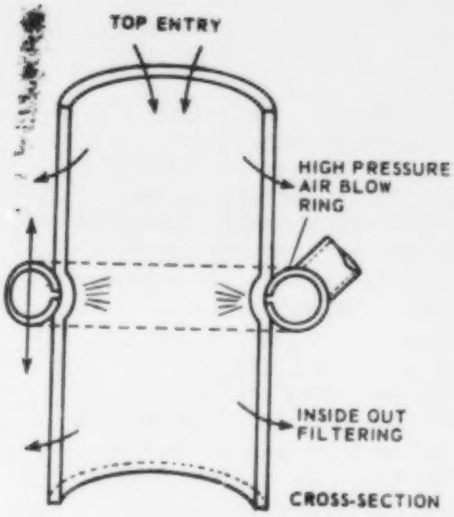
streamline and hence impact upon the filter filament. This type of collection is described by the mechanism of inertial impaction. Extremely small particles, i.e., those in the size range of 0.01 to 0.5 microns in diameter, are captured via the diffusion mechanism. These particles do not follow the fluid streamlines because they collide with gas molecules and, hence follow an erratic path as shown in figure VII-4. This random motion, called Brownian motion, increases the chance of particle contact with the filter filament. The electrostatic forces existing between the particle and the filter filament draw particles toward the filament and cause some particles to be captured. This electrostatic force may exist as either a direct charge or an induced charge. The final particle collection mechanism results in the greatest amount of particle collection and is called sieving. When a layer of particles begins to build up on the fabric, dust particles iminge upon this layer and are collected. The gas stream passes around and through the layer intersticies.

7.1.5.2 Fabric Filter Equipment

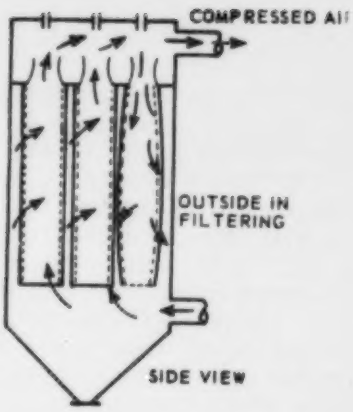
The fabric filter material may be felted or woven fabric. Woven fabric bags are made from cotton, wool, Dacron, Nylon, Orlon, Nomex, polypropylene, Teflon, and fiberglass. Characteristics such as yarn type (monofilament, multifilament, and spun staple) and weave type (twill, plain, and sateen) are determining factors in cloth permeability and hence air-to-cloth ratios. The cloth permeability or resistance is part of the total filter resistance and is usually less than 0.1 in H_2O. Dust resistance is related to dust concentration, particle size, and gas face velocity. A filter resistance coefficient, K, is used to describe these types of resistance. Felted fabric bags are made from wool, Dacron, Nylon, Nomex, Teflon, and polypropylene. The use of a felted fabric bag results in higher collection efficiency for some particles and are used with reverse jet or jet pulse baghouses. Higher air-to-cloth ratios (cfm per ft^2) are used with felted fabrics (about 6:1 to 16:1 versus 1:1 to 5:1).

Reverse jet and jet pulse refer to the method of cleaning the bags in a baghouse. Manual shaking, mechanical shaking, air shaking, air bubbling and reverse air flexing are additional methods. Figure VII-5 illustrates these methods. In all methods the purpose of cleaning is to knock the dust layer which has built up on the bag off and into a collection hopper at the base of the baghouse. This cleaning is normally done when the pressure drop becomes excessive or on a timed cycle.

The baghouse structure may be designed to be one of three basic types, 1) open pressure, 2) closed pressure, or 3) closed suction. These are illustrated in figure VII-6. The difference between the closed pressure and open pressure type is that the baghouse structure is completely closed to the outside atmosphere in the closed pressure type. This type of baghouse is used primarily when handling highly toxic gases or those gases with a high dew point. Location of the fan on the inlet side of the baghouse rather than on the outlet side distinguishes the pressure type from the suction type of baghouse.


TOP ENTRY
HIGH PRESSURE AIR BLOW RING
INSIDE OUT FILTERING
CROSS-SECTION

Reverse jet cleaning of dust collector bags.


COMPRESSED AI
OUTSIDE IN FILTERING
SIDE VIEW

Jet pulse dust collector bag

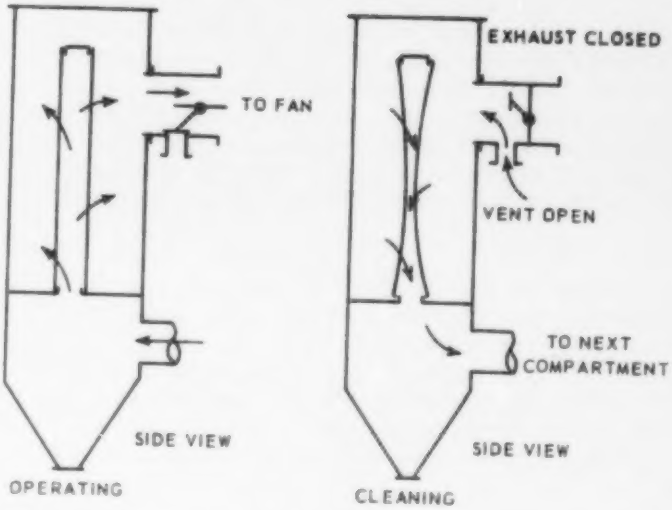
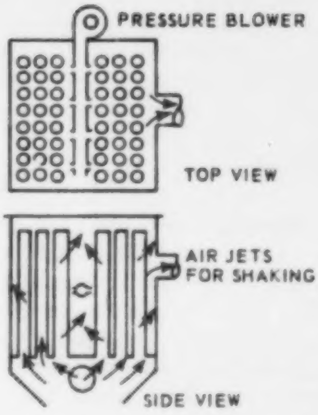

TO FAN
SIDE VIEW
OPERATING
EXHAUST CLOSED
VENT OPEN
TO NEXT COMPARTMENT
SIDE VIEW
CLEANING

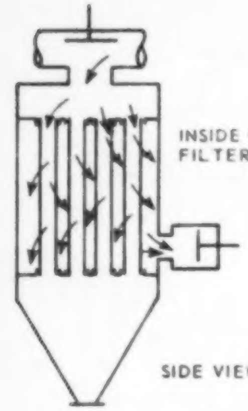
Figure 4-82. Cloth cleaning by reverse flow of ambient air.


PRESSURE BLOWER
TOP VIEW
AIR JETS FOR SHAKING
SIDE VIEW

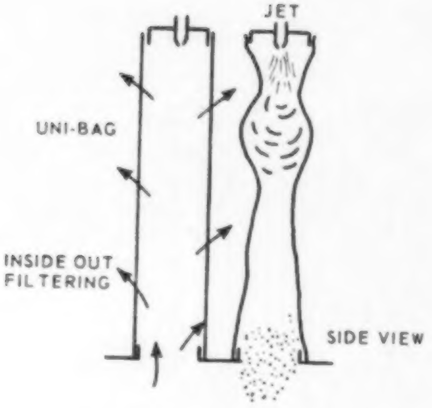
Air shaking wind-whip cleans dust collector bags.

Figure VII-5

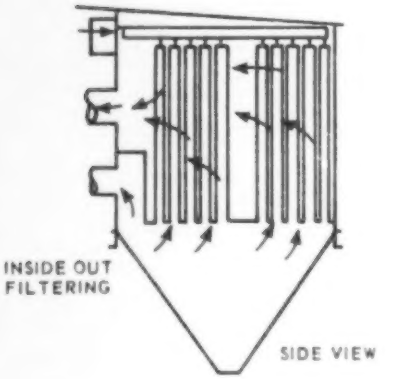
Fabric Filter Cleaning Methods


INSIDE OUT FILTERING
SIDE VIEW

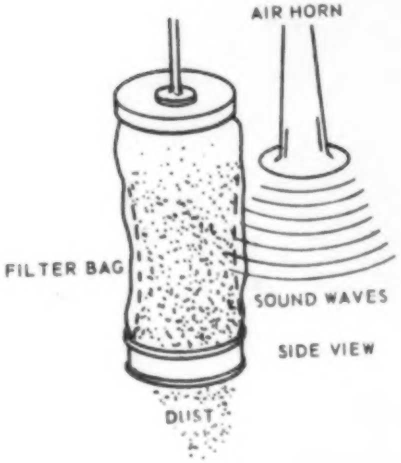
Repressuring cleaning of dust collector bags.


JET
UNI-BAG
INSIDE OUT FILTERING
SIDE VIEW

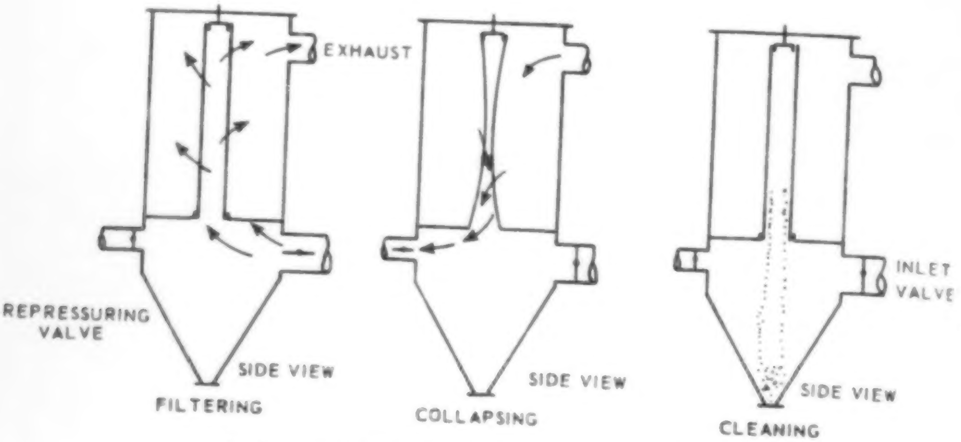
Bubble cleaning of dust collector bags.


INSIDE OUT FILTERING
SIDE VIEW

Mechanical shaking of bottom entry design uni-bag dust collector.


AIR HORN
FILTER BAG
SOUND WAVES
SIDE VIEW
DUST

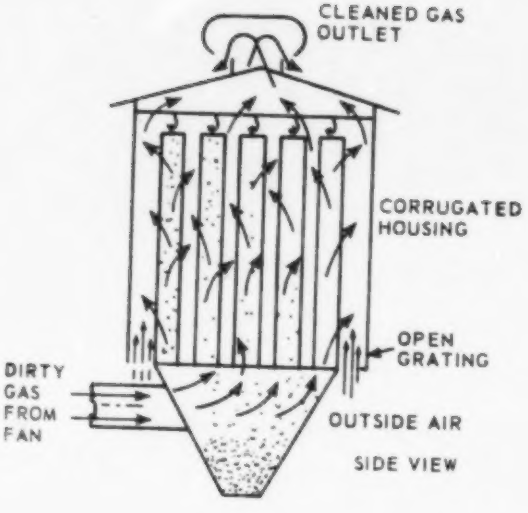
Sonic cleaning of dust collector bags.


EXHAUST
REPRESSURING VALVE
SIDE VIEW
FILTERING
SIDE VIEW
COLLAPSING
INLET VALVE
SIDE VIEW
CLEANING

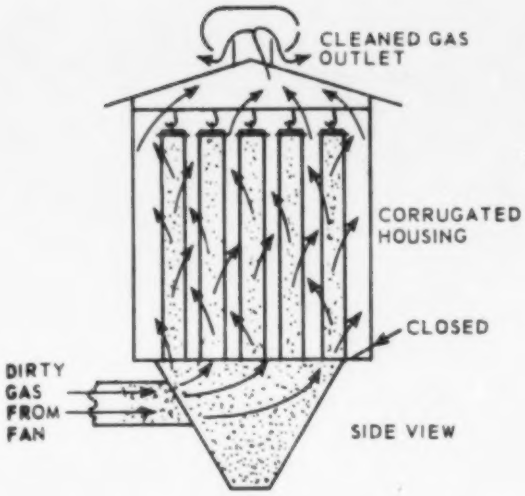
Reverse air flexing to clean dust collector bags by repressuring.

Figure VII-5 (continued)

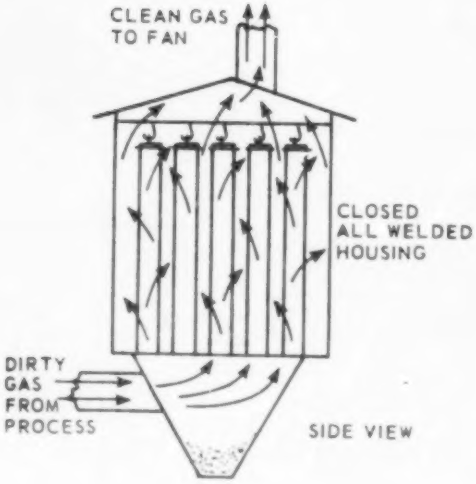
Fabric Filter Cleaning Methods


CLEANED GAS OUTLET
CORRUGATED HOUSING
OPEN GRATING
DIRTY GAS FROM FAN
OUTSIDE AIR
SIDE VIEW

Open pressure baghouse.


CLEANED GAS OUTLET
CORRUGATED HOUSING
CLOSED
DIRTY GAS FROM FAN
SIDE VIEW

Closed pressure baghouse.


CLEAN GAS TO FAN
CLOSED ALL WELDED HOUSING
DIRTY GAS FROM PROCESS
SIDE VIEW

Closed suction baghouse.

Figure VII-6

Baghouse Structures

7.1.5.3 Application

Fabric filter installations on power plants are increasing in number. Design of materials to handle higher temperature gases and the demand for cleaner air are two factors which are prompting consideration of the use of fabric filtration. Higher initial and operating costs are disadvantages to be balanced against dependable service and high collection efficiency. The collection of sub-micron particles is a key advantage of this method.

7.2 SULFUR OXIDES CONTROL

There has been a limited amount of research and development work performed on treating a fabric filter with a material such as dolomite in order to achieve a small degree of SO_2 control. Some SO_2 removal is achieved when collecting particulate matter with an ESP because of the adsorption of SO_2 onto fly ash. Highly alkaline fly ash such as that obtained when burning lignite may adsorb about 15 percent of the SO_2. Fly ash low in alkalinity may still adsorb about 5 percent. The major control technique being developed, however, is that of wet scrubbing using an alkaline reagent to collect the SO_2, Collection efficiencies of as high as 90 percent have been demonstrated on a pilot plant basis. Methods other than flue gas desulfurization (FGD) are available, but many of these methods are less economical or less resource utilization efficient. (See Table VII-1). The technological feasibility and the reliability of FGD processes is the subject of an on-going debate among government agencies, utility industry, and process vendors. A special public hearing was held in Washington, D.C. from October 18 to November 2, 1973 in order to review the status of the SO_2 FGD technique. A report (6) issued by the hearing panel contains the findings and conclusions of these hearings.

The EPA position stated at these hearings was summarized as follows:

(1) FGD technology represents a viable means of achieving power plant SO_2 control while allowing use of plentiful high sulfur fuels.

(2) No alternative control technology is expected to make a major impact before 1980.

(3) Technological feasibility of FGD Systems has been established; it should not be considered a decisive factor in system utilization.

(4) FGD costs are comparable to Low-Sulfur Cost Increments.

(5) A large fraction of the nation's coal-fired power plants can be fitted with commercially available FGD systems and meet SO_2 control requirements.

Table VII-1

COMPARISON OF ALTERNATE APPROACHES FOR UTILITIES TO MEET THE 1975-1977 SO_x CONTROL STANDARDS

Technology Type	Relative Complexity[1] 1-10	Potential Applicability by 1985 % of Total Power Plant Fuel Utilization Which Could Be Served			Energy Loss In Process %	Effective Total Cost of Fuel (Raw Fuel + Clean-Up Costs) Mils/Kwh	Data Technology Commercial Available For Application to Power Plants
		Retrofit	New Boilers	Total			
Naturally Clean Fuels	1	60	40	50	0	4.6 - 6.0	Current
Flue Gas Cleaning	2-3	70	100	85 [2]	4-7	4.5 - 6.7	1972-74
High BTU Coal Gasification	8-10	—	—	0 [3]	30	12+	1980-85
Coal Liquefaction	8-10	—	—	0 [3]	30	10+	1980-85
Fluid Bed Combustion of Coal	5	0	30-50 [4]	15	2	2.5 - 5.7[5]	1977-78
Chemical Coal Cleaning	4-5	30-40[4]	30-40 [4]	30-40	10	4.0 - 5.5	1977-78
Low BTU Gasification	7-10	—	—	<10 [6]	20	7.0 - 10.0	1978-83

1. Based on Number of Major Pieces of Equipment, and Process Steps and Complexity (1 is simplest).

2. This is what could be done if necessary, however available clean fuels will probably handle up to 50% of total capacity.

3. Based on DOI Projection, United States Energy Through the Year 2000, DuPree & West, Dec. 1972.

4. Limited by time from date of availability to 1985.

5. Tentative Cost Estimate

6. Based on Mitre Study (1973) with Energy/Fuel Projections to 2000.

(6) The required reliability of FGD systems has been achieved on selected units.

(7) Although disposal of sludges from some FGD systems can potentially lead to environmental problems, technology is available which appears to alleviate any water pollution and land utilization problems.

Item number 6, i.e., that concerning the reliability of the system, appears to be the most contested factor in FGD. The industry does not feel that the reliability of FGD has been proven. The American Electric Power System is bitterly contesting the contention of FGD reliability. Court suits have been filed on the issue and are in litigation. Figure VII-7 shows the present and projected level of development of FGD.

7.2.1 FGD Processes

The FGD processes may be generally classified as either throwaway or saleable product systems. Only a few processes have undergone enough development to be considered as viable candidates for commercial application in the near future. These processes are categorized and listed below.

Throwaway Systems

Lime scrubbing

Limestone scrubbing

Double alkali

Saleable Product Systems

Magnesium Oxide scrubbing

Sodium sulfite scrubbing

Catalytic oxidation

Table VII-2 shows the number of power plants constructing or planning the construction of a FGD system. Also shown is the type of system being placed in operation. Table VII-3 lists a more detailed breakdown of these same data.

CUMULATIVE U.S. POWER PLANT CAPACITY WITH INSTALLED SO_x CONTROL

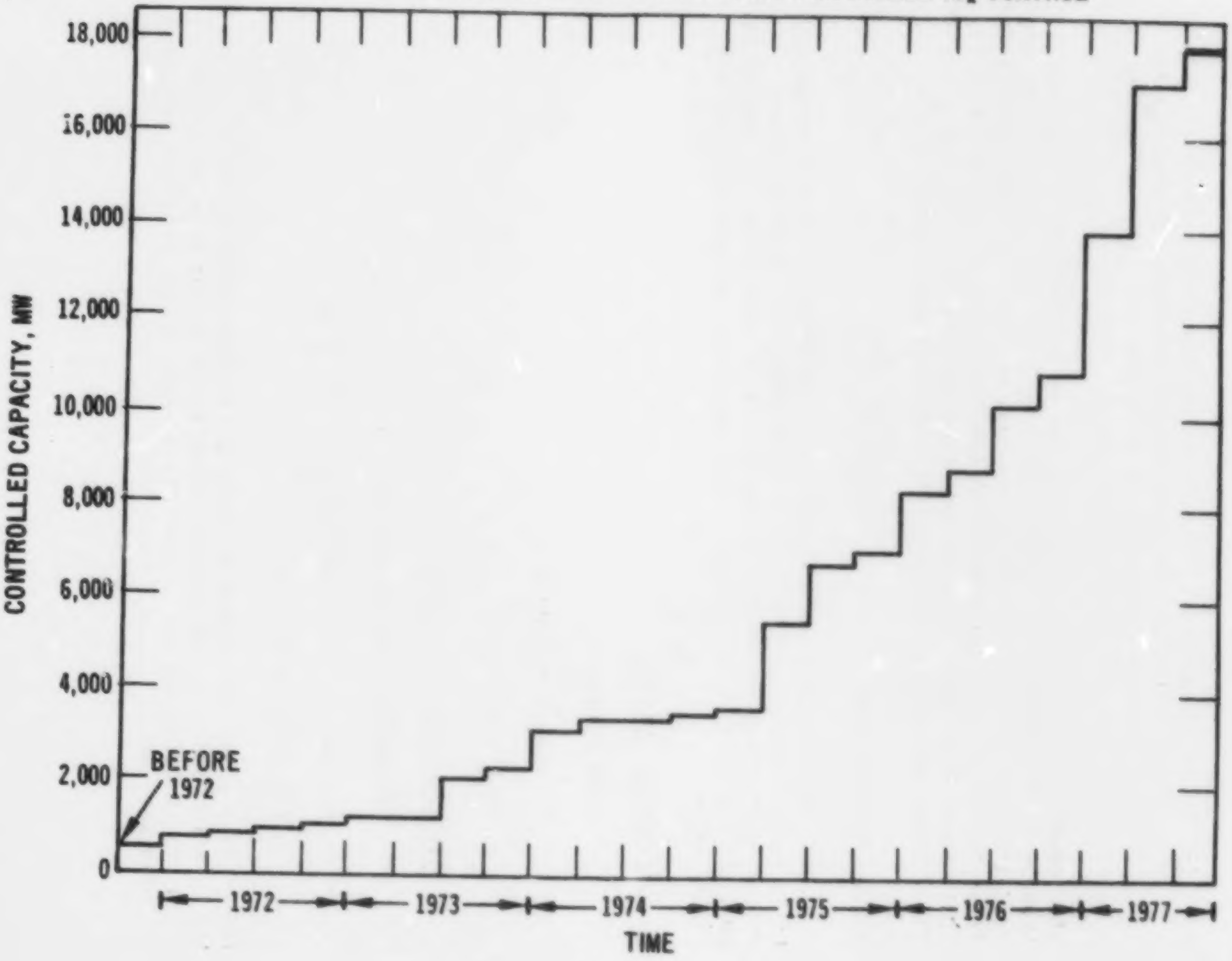


Figure VII-7

TABLE VII-2

SUMMARY OF ELECTRIC UTILITY FLUE GAS DESULFURIZATION FACILITIES

MW Capacity (No. of Units)

PROCESS	OPERATIONAL	UNDER CONSTRUCTION	PLANNED	TOTALS	NEW PLANTS	RETROFIT ON EXISTING PLANTS
Limestone	1904 (8)	1570 (4)	13027(27)	16501(39)	29	10
Lime	715 (4)	2910 (5)	5038(18)	8663(27)	8	19
Limestone or Lime	30 (1)	--	6085(10)	6115(11)	7	4
Magnesium Oxide	250 (2)	120 (1)	487 (2)	857 (5)	--	5
Catalytic Oxidation	110 (1)	--	--	110 (1)	--	1
Wellman-Lord	--	830 (3)		830 (3)	1	2
Aqueous Na Based	250 (2)	125 (1)	--	375 (3)	--	3
Double Alkali	32 (1)	--	--	32 (1)	--	1
Process Not Selected	--	--	1900 (3)	1900 (3)	2	1
TOTALS	3291(19)	5555(14)	26537(60)	35383(93)	47	46

Table VII-3. PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973 (6)

Limestone Scrubbing

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Commonwealth Edison Will County No. 1	R	156	B&W	Coal, 3.5%	Operational (Feb. 1972)
Kansas City Power & Light, Hawthorn No. 4	R	100	CE	Coal, 3.5%	Operational (Aug. 1972)
Kansas City Power & Light, LaCygne Sta.	N	820	B&W	Coal, 5%	Operational (June 1973)
Arizona Public Service Cholla Station	R	115	Research Cottrell	Coal, 0.4 - 1.0%	Under Construction (October 1973)
Detroit Edison St. Clair No. 6	R	180	Peabody Engineering	Coal, 3.7%	Under Construction (Dec. 1973)
Southern California Edison (operating agent) Mohave Sta.	R	160	UOP	Coal, 0.5 - 0.8%	Under Construction (March 1974)
TVA Widow's Creek No. 8	R	550	TVA	Coal, 3.7%	Under Construction (May 1975)
Northern States Power Sherburne County No.1	N	680	CE	Coal, 1%	Under Construction (May 1976)
Public Service of Indiana, Gibson Sta.	N	650	CE	Coal, 1.5%	Planned (1976)
Northern States Power Sherburne County No. 2	N	680	CE	Coal, 1%	Planned (May 1977)

Table VII-3 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Lime Scrubbing

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Union Electric Co. Meramec No. 2	R	140	CE	Coal, 3%	Abandoned (Sept. 1968)
Kansas Power & Light Lawrence No. 4	R	125	CE	Coal, 3.5%	Operational (Dec. 1968)
Kansas Power & Light Lawrence No. 5	N	430	CE	Coal, 3.5%	Operational (Nov. 1971)
Kansas City Power & Light, Hawthorn No. 3	R	100	CE	Coal, 3.5%	Operational (Nov. 1972)
Louisville Gas & Electric Paddy's Run No. 6	R	70	CE	Coal, 3%	Operational (April 1973)
Duquesne Light Co. Phillips Station	R	100	Chemico	Coal, 2%	Under Construction (Nov. 1973)
Southern California Edison (operating agent) Mohave Sta.	R	160	SCE/Stearns-Roger	Coal, 0.5 - 0.8%	Under Construction (Dec. 1973)
Ohio Edison/Mansfield Sta. (2 units)	N	1650	Chemico	Coal, 4.3%	Under Construction (Early 1975)
Montana Power Colstrip No. 1 & 2	N	720	CEA	Coal, 0.8%	Under Construction (May 1975)
Columbus & Southern Conesville No. 5 & 6	N	750	Not Selected		Planned (1976)

Table VII-3 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

L/LS Not Selected

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Salt River Project Navajo No. 1	N	750	Not selected	Coal, 0.5–0.8%	Construction Start, Nov. 1974 (Mar.'76)
Salt River Project Navajo No. 2	N	750	Not selected	Coal, 0.5–0.8%	Construction Start, Oct. 1975 (Oct.'76)
Arizona Public Ser. Four Corners No. 1	R	175	Not selected	Coal, 0.75%	Construction Start, Oct. 1975 (Oct.'76)
Arizona Public Ser. Four Corners No. 2	R	175	Not selected	Coal, 0.75%	Construction Start, Nov. 1975 (Dec.'76)
Southern California Edison (operating agent) Mohave No. 1&2	R	1180	Not selected	Coal, 0.5–0.8%	Planned (Dec. 1976)
Arizona Public Ser. Four Corners No. 3	R	229	Not selected	Coal, 0.75%	Construction Start, June 1976 (Mar.'77)
Salt River Project Navajo No. 3	N	750	Not selected	Coal, 0.5–0.8%	Construction Start, Mar. 1976 (Mar.'77)
Arizona Public Ser. Four Corners No. 4	R	800	Not selected	Coal, 0.75%	Construction Start, Sept. 1975 (Apr.'77)
Arizona Public Ser. Four Corners No. 5	R	800	Not selected	Coal, 0.75%	Construction Start, Nov. 1976 (June '77)

Table VII-3 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Magnesium Oxide Scrubbing					
Boston Edison Mystic No. 6	R	150	Chemico	Oil, 2.5%	Operational (April 1972)
Potomac Electric & Power Dickerson No. 3	R	100	Chemico	Coal, 2%	Operational (Sept. 1973)
Philadelphia Electric Eddystone No. 1	R	120	United Engineers	Coal, 2.5%	Under Construction (Dec. 1973)
Other SO_2 Control Systems					
Catalytic Oxidation (Cat-Ox)					
Illinois Power Co. Wood River No. 4	R	110	Monsanto	Coal, 3.2%	Operational (Oct. 1972)
Wellman-Lord					
Northern Indiana Public Service, D.H.Mitchell No.11	R	115	Davy Powergas/ Allied Chemical	Coal, 3.5%	Under Construction (Early 1975)
Aqueous Sodium Base Scrubbing, Non-Regenerable					
Nevada Power Reid Gardner No. 1&2	R	250	CEA	Coal, 0.5 - 1.0%	Under Construction (Dec. 1973)
Nevada Power Reid Gardner No. 3	R	125	CEA	Coal, 0.5 - 1.0%	Under Construction (1975)
Dry Adsorption					
Indiana & Michigan Electric, Tanner's Creek Station	R	150	B&W/Esso	Coal,	Under Construction (1974)

Table VII-3 (continued). PLANNED AND OPERATING FLUE GAS DESULFURIZATION UNITS ON U.S. POWER PLANTS, SEPTEMBER 1973

Process Not Selected

Utility Company Power Station	New or Retrofit	Size of FGD Unit (MW)	Process Vendor	Fuel and Sulfur Content	Status (Start-Up Date)
Public Service of New Mexico San Juan No. 2	R	100	Not Selected	Coal, 0.8%	Planned (Nov. 1974)
Potomac Electric & Power Chalk Point No. 3	N	630	Not Selected	Oil	Planned (1975)
Potomac Electric & Power Chalk Point No. 4	N	630	Not Selected	Oil	Planned (1976)
Potomac Electric & Power Dickerson No. 4	N	800	Not Selected	Coal, 2%	Planned (1976)
Potomac Electric & Power Dickerson No. 5	N	800	Not Selected	Coal, 2%	Planned (1977)

A discussion of each of the processes pointing out the process chemistry, the efficiency, and the advantages and disadvantages is considered to be of merit. This discussion follows.

7.2.1.1. Lime and Limestone Flue Gas Desulfurization Processes

Process

Several methods have been developed for the use of limestone and lime slurries in a wet scrubbing process. The major variations are as follows: (See Figure VII-8)

(1) use of limestone ($CaCO_3$) added to the scrubber circuit

(2) use of hydrated lime ($Ca(OH)_2$) added to the scrubber circuit

(3) use of limestone injected in the boiler affecting calcination to lime with subsequent lime slurry scrubbing.

In all three process modes, a slip stream subjected to a dewatering operation consisting of reaction products, flyash, and unreacted alkali is discharged as waste to either a disposal pond or landfill site.

The overall reactions for limestone and lime scrubbing can be represented by reactions (1) and (2) respectively:

(1) $CaCO_3 + SO_2 + 1/2H_2O \rightarrow CaSO_3.1/2H_2O + CO_2$

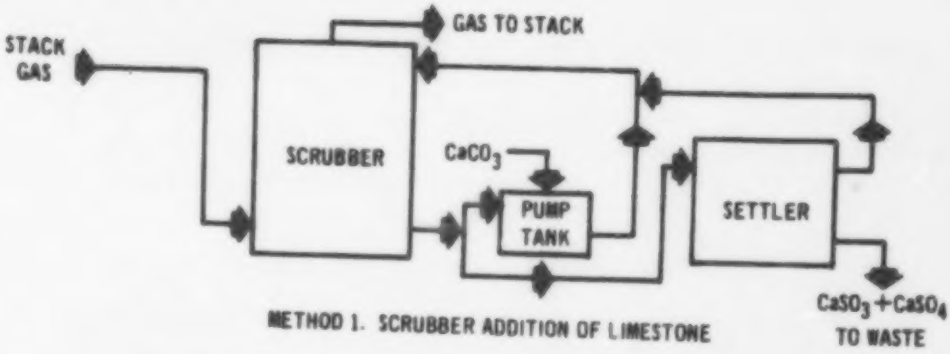
(2) $Ca(OH)_2 + SO_2 \rightarrow CaSO_3.1/2H_2O + 1/2H_2O$

History and Experience

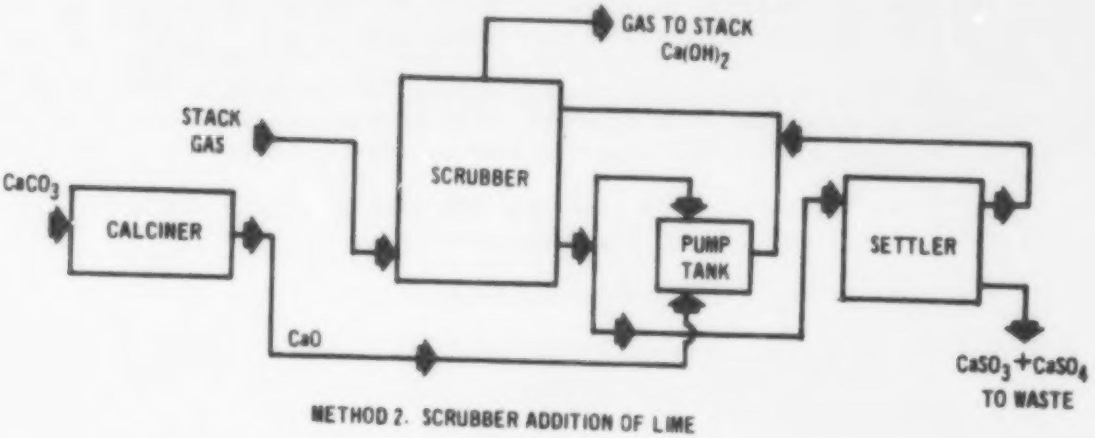
There has been a considerable amount of bench model, pilot plant, and full scale activity since the early 1930's. Over the last 5 years developmental activities have been particularly intense and 31 full scale commercial systems have been ordered in the U. S. since 1968, of which 7 have started-up and have a backlog of operating experience.

The boiler injection plus wet scrubbing process has been extensively tested on a commercial scale by Combustion Engineering, Inc., (C.E.) since 1968. After 4 years of intermittent operation filled with numerous technical difficulties, C. E. no longer offers this process; C.E. favors the lime/limestone tail-end scrubbing process.

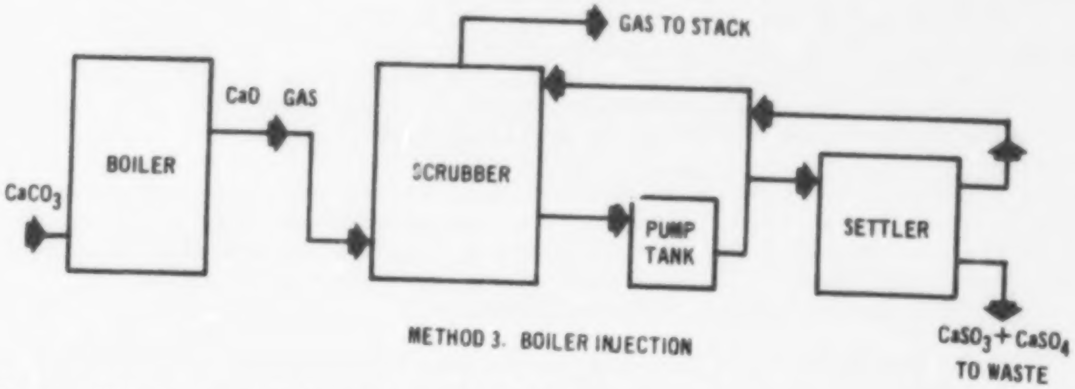
The first full scale installation in this country that uses limestone introduced into the scrubbing circuit is the 175 megawatt Commonwealth Edison Will County Station - Unit No. 1. This unit was started up in February 1972, and has operated intermittently since then, achieving SO_2 removal efficiencies in the range of 75 to 85 percent. The major problems experienced to date have involved demister pluggage by a soft, mud-like substance, system reliability caused by mechanical problems, and finding an economic means for disposal of waste sludge. A great deal has been learned in the past year at the Will County Unit concerning practical operating problems with limestone scrubbing. None of the problems encountered at this unit appear to be insurmountable.


STACK GAS
GAS TO STACK
SCRUBBER
$CaCO_3$
PUMP TANK
SETTLER
$CaSO_3 + CaSO_4$ TO WASTE

METHOD 1. SCRUBBER ADDITION OF LIMESTONE


GAS TO STACK
$Ca(OH)_2$
STACK GAS
$CaCO_3$
CALCINER
SCRUBBER
PUMP TANK
SETTLER
CaO
$CaSO_3 + CaSO_4$ TO WASTE

METHOD 2. SCRUBBER ADDITION OF LIME


GAS TO STACK
BOILER
CaO GAS
$CaCO_3$
SCRUBBER
PUMP TANK
SETTLER
$CaSO_3 + CaSO_4$ TO WASTE

METHOD 3. BOILER INJECTION

Figure VII-8. Major process variations for use of lime or limestone for removal of SO_2 from stack gases.

Additional valuable information concerning operation of lime/limestone scrubbing processes is being gathered at the versatile EPA prototype test facility at the TVA Shawnee Steam Plant. The 30 megawatt facility includes three types of 10 megawatt (equivalent) scrubbers (venturi, TCA, and marble-bed), extensive process instrumentation, and sophisticated data acquisition and handling systems. Tests to date have identified test conditions which have led to reliable operation during tests up to 1 month in duration.

The most recent successful operation of a lime wet scrubbing process is the 70 megawatt installation at Louisville Gas and Electric Company's Paddy's Run Station. The unit uses carbide sludge ($Ca(OH)_2$) as the alkaline absorbent. No scaling or plugging problems have been encountered in over 1000 hours of closed-loop operation since April 1972. The system has demonstrated near 100 percent availability while removing 85 to 95 percent of the flue gas from boilers fired with 3.5 to 4.0 percent sulfur. Waste sludge is thickened, filtered, and disposed of as untreated landfill.

The most successful lime scrubbing system is Chemico's Mitsui Aluminum Company's facility. This 156 megawatt power plant has been retrofitted with two Chemico dual-stage venturi scrubbing systems, each capable of handling 75 percent of the full load gas flow. The system has demonstrated reliable, trouble-free operation since being put on-stream in March 1972. The plant is presently burning 2 percent sulfur coal (1800 to 2200 ppm inlet SO_2) and achieving 80 to 85 percent SO_2 removal from the flue gas using carbide sludge as the alkaline absorbent. Since coming on-stream, the system has operated at near 100 percent availability. The absence of scaling difficulties has been attributed to operational data developed by Mitsui in extensive pilot plant tests (in Japan) and to precise pH control.

SO2 Removal Efficiency

A survey of the seven companies having experience in full-scale tail-end wet scrubbing shows that most companies will provide SO_2 removal guarantees varying from 70 to 90 percent, or as required to meet EPA standards.

Advantages and Disadvantages

The advantages of lime and limestone systems are as follows:

(1) relatively low capital and operating costs

(2) potentially high SO_2 removal efficiencies

(3) ability to simultaneously remove both SO_2 and particulates

(4) most fully characterized of flue gas desulfurization systems

The disadvantages are:

(1) requirement to dispose of large quantities of waste sludge in an environmentally acceptable manner

(2) If not carefully designed, a tendency toward chemical scaling, plugging, and erosion problems.

Performance and Reliability Summary

Operating experience at the Mitsui, Shawnee, and Louisville Gas and Electric scrubbers indicates that lime/limestone scrubbers which have the alkali added to the scrubber circuit can be made to operate reliably. The Mitsui unit in particular has demonstrated reliable operation of this technology over 1 1/2 years.

However, experience at other facilities indicates that reliability can be a problem if the systems are not carefully designed and operated. Also, the boiler injection mode has proven to be a troublesome configuration (Union Electric and KansasCity Power & Light units) prone to serious operating problems.

7.2.1.2 Double Alkali Flue Gas Desulfurization Process

(See Figure VII-9)

The many double alkali process variations involve the scrubbing of flue gases with a clear liquor containing dissolved sodium or ammonium salts, followed by treatment of the depleted liquor with lime or limestone in a reaction producing a throwaway sludge for disposal and alkali liquor for scrubbing. Typical reactions occuring in the scrubber and reaction tank, respectively, are as follows for a sodium-based system:

(1) $Na_2SO_3 + SO_2 + H_2 \longrightarrow 2NaHSO_3$

(2) $2NaHSO_3 + Ca(OH)_2 \longrightarrow Na_2SO_3 + 3/2H_2O + CaSO_3.1/2H_2O$

History and Experience

In the United States primary developmental attention has been placed on sodium-based double alkali systems using lime for regeneration. Important pilot plant work has been performed by General Motors, FMC Corp., Envirotech, A. D. Little/Combustion Equipment Associates, and Chemico.

Southern Co. is planning to test a double alkali system on equivalent 20 megawatts of coal combustion flue gas at the Sholz plant operated by Gulf Power Co. in Florida.

Intensive development of double alkali systems has been performed in Japan, with limestone used as the input alkali and gypsum produced as a saleable product. Showa Denko has recently started-up a 156 megawatt system on an oil-fired power plant. Two additional 150 megawatt units treating oil-fired boilers using Kawasaki/Kureha technology are under construction and will start-up in 1974.

SO_2 Removal Efficiency

Based on pilot scale results to date, SO_2 removal efficiencies between 90 and 99 percent are achievable at reasonable costs.

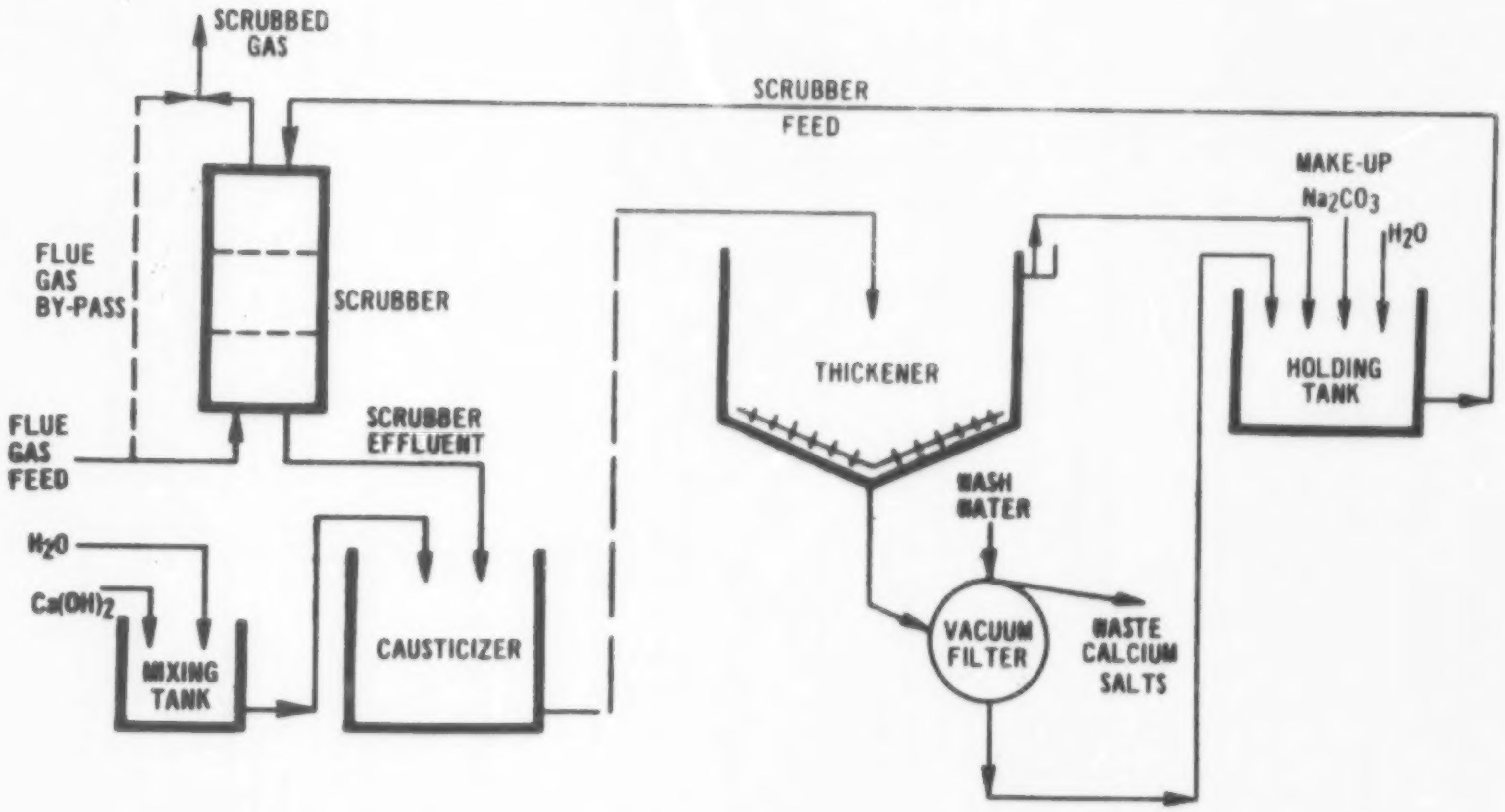

SCRUBBED GAS
SCRUBBER FEED
MAKE-UP Na_2CO_3
H_2O
FLUE GAS BY-PASS
SCRUBBER
THICKENER
HOLDING TANK
FLUE GAS FEED
SCRUBBER EFFLUENT
WASH WATER
H_2O
$Ca(OH)_2$
MIXING TANK
CAUSTICIZER
VACUUM FILTER
WASTE CALCIUM SALTS

Figure VII-9. Double alkali process variation - sodium scrubbing with lime regeneration.

Advantages and Disadvantages

The advantages of double alkali systems include:

(1) relatively low capital and operating costs

(2) very high SO_2 removal efficiencies can be obtained

(3) use of clear solution scrubbing minimizes solids buildup and erosion problems offering potential for high reliability

(4) ability to simultaneously remove SO_2 and particulates

Disadvantages include:

(1) Requirement to dispose of large quantities of waste sludge in an environmentally acceptable manner

(2) Design complexities necessary to deal with the following problems:

  (a) necessity to prevent excessive purge of Na_2SO_4 produced as a result of oxidation (Na_2SO_4 is difficult to regenerate)

  (b) necessity to avoid scrubbing with clear liquor saturated with calcium sulfate which could lead to scaling problems

Performance and Reliability Summary

Based on pilot scale operating experience at General Motors, FMC Corp., Envirotech, A. D. Little in the United States, and Kureha and Showa Denko in Japan, double alkali systems offer potentially high SO_2 removal (>90 percent) with high reliability.

7.2.1.3 Magnesium Oxide SO_2 Scrubbing Process - Saleable Product

(See Figure VII-10)

The Chemico/Basic MgO process utilizes an aqueous slurry of magnesium oxide, magnesium sulfite and magnesium sulfate to scrub SO_2 from flue gas streams. The major reaction involves the formation of additional magnesium sulfite through combination of SO_2 and magnesium oxide. Magnesium sulfite removed from the scrubber loop is dried and subsequently calcined to drive off SO2 and regenerate active MgO for return to the scrubber loop. The regeneration can be accomplished either at the power plant site or at some remote location since the magnesium sulfite and magnesium oxide are stable solids capable of being shipped. The SO_2 generated in the calcining operation can be converted to high grade sulfuric acid or to elemental sulfur by provision of the appropriate equipment.

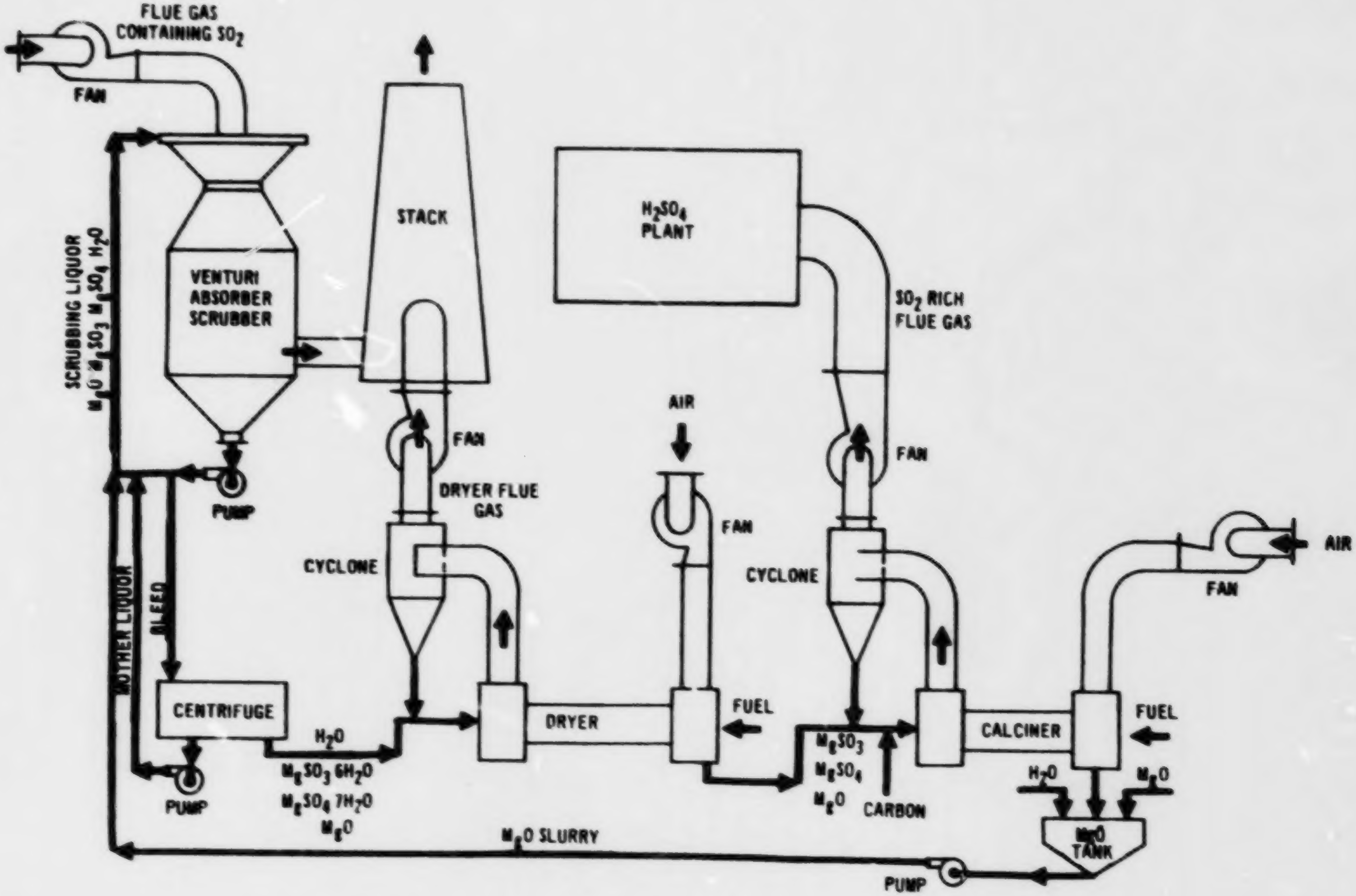

FLUE GAS CONTAINING SO_2
FAN
SCRUBBING LIQUOR
M_gO M_gSO_3 M_gSO_4 H_2O
VENTURI ABSORBER SCRUBBER
STACK
H_2SO_4 PLANT
SO_2 RICH FLUE GAS
FAN
PUMP
MOTHER LIQUOR
BLEED
DRYER FLUE GAS
AIR
FAN
FAN
CYCLONE
CYCLONE
AIR
FAN
CENTRIFUGE
H_2O
M_gSO_3 $6H_2O$
M_gSO_4 $7H_2O$
M_gO
DRYER
FUEL
M_gSO_3
M_gSO_4
M_gO
CARBON
CALCINER
FUEL
H_2O
M_gO
MgO TANK
PUMP
M_gO SLURRY
PUMP

Figure VII-10. MgO slurry process - for flue gas free of particulate matter.

History and Experience

In June of 1970 EPA entered into an agreement with Chemico/Basic, Boston Edison Company and Essex Chemical Company for construction and operation of the Chemico/Basic Magnesia Slurry Process on the No. 6 boiler at Boston Edison's Mystic Station in Everett, Massachusetts. The installation on this 155 megawatt oil-fired boiler was completed in May of 1972. The year following completion of the system has been devoted to equipment modifications and investigations directed toward solving numerous operational problems which developed. Most of the problems which were encountered were of a materials-handling nature resulting from the character of the solids generated in the scrubber loop. The fact that most of these problems have been satisfactorily solved is demonstrated by the 85 to 90 percent availability factor for June and July of this year. Some equipment modifications are continuing to improve operability.

An additional MgO system has recently been started in September of this year at Potomac Electric Power Co.'s Dickerson Station. This unit will handle one-half the flue gas from a 195 megawatt coal-fired unit. The system is designed to accommodate flue gas from the burning of 3.0 percent sulfur coal. Very early results are encouraging. An additional coal-fired application designed and engineered by United Engineers & Constructors is nearing completion at Philadelphia Electric's Eddystone Station. This unit, which is due for a December 1973 startup, will handle the equivalent of 120 megawatts with 2.5 percent sulfur coal fuel.

Advantages and Disadvantages

The major advantages to the MgO process are summarized as follows:

(1) sulfur can be recovered as high grade acid or elemental sulfur depending upon equipment provided for regeneration

(2) regeneration can be accomplished at a location quite distant from the power plant (for instance, at an existing sulfuric acid plant) thus permitting the use of a central regeneration facility servicing several flue gas cleaning locations.

(3) by maintaining adequate inventories of MgO, extended outages of the regeneration facility can be tolerated without interruption of the pollution control facility.

(4) process reliability has benefitted from the modifications and investigations at the Boston Edison site and will continue to improve as the two additional systems (Potomac and Philadelphia) become fully operational in the near future.

The major disadvantage of the process is the lack of reliable long term operating experience and a lack of experience with coal fired power plants.

SO_2 Removal Efficiency

The MgO process is capable of achieving 90 percent SO_2 removal over a wide range of inlet SO_2 concentrations.

Performance and Reliability

The experience to date at Boston Edison has established the capability of the process to consistently achieve 90 percent SO_2 removal. Also, the high turndown capability and the reliable operation of the venturi scrubber configuration used at Boston Edison have both been established. The reliability of the entire MgO process has not as yet been established through long term operation; however, the on-stream time at Boston Edison has improved with the various modifications to achieve an 85 to 90 percent availability for June and July 1973. Modifications to improve system reliability are continuing.

7.2.1.4 Wellman-Lord Flue Gas Desulfurization Process

(See Figure VII-11)

The Wellman-Lord (W-L) SO_2 Recovery Process utilizes a sodium sulfite-sodium bisulfite solution to absorb SO_2 from flue gas. The spent absorbent, rich in bisulfite, is processed in a steam-heated evaporator, regenerating active sodium sulfite crystals and producing a stream of SO_2 for further processing. The process, depicted in simplest form is:

- Absorption

$$SO_2 + Na_2SO_3 + H_2O \rightarrow 2NaHSO_3$$

- Regeneration

$$2NaHSO_3 \xrightarrow[\text{heat}]{} Na_2SO_3 \downarrow + SO_2 \uparrow + H_2O \uparrow$$

Inactive sodium sulfate is formed by three mechanisms: SO_3 absorption, disproportionation, and sulfite oxidation. Sodium sulfate must be purged from the system in order to maintain adequate levels of active sulfite in the absorber/evaporator loop.

History and Experience

Patents for the W-L Process were filled in 1966 and patent rights are currently held by Davy Powergas, Inc., Lakeland, Fla. Two Japanese firms are licensed to market the system. There are currently seven operating plants in the U. S. and Japan including two oil-fired boiler applications. Additionally, more than ten systems are on order, including five more boiler applications. The earliest operating W-L System is the sulfuric acid plant application at Paulsboro, New Jersey, which has been operating since July of 1970. The earliest boiler application is the industrial boiler (oil-fired) at Japan Synthetic Rubber Co., Chiba, Japan. This unit, equivalent to 75 megawatts, has been operating successfully since August of 1971 and has an excellent on-stream factor of 97 percent since that time. It is worthy of note that both Japan Synthetic Rubber (JSR) and Olin Corporation (owner of the Paulsboro system) have ordered additional systems, thus attesting to the satisfactory performance of the W-L System. Standard Oil of California purchased a W-L System for Claus Plant tailgas cleanup which was started in June

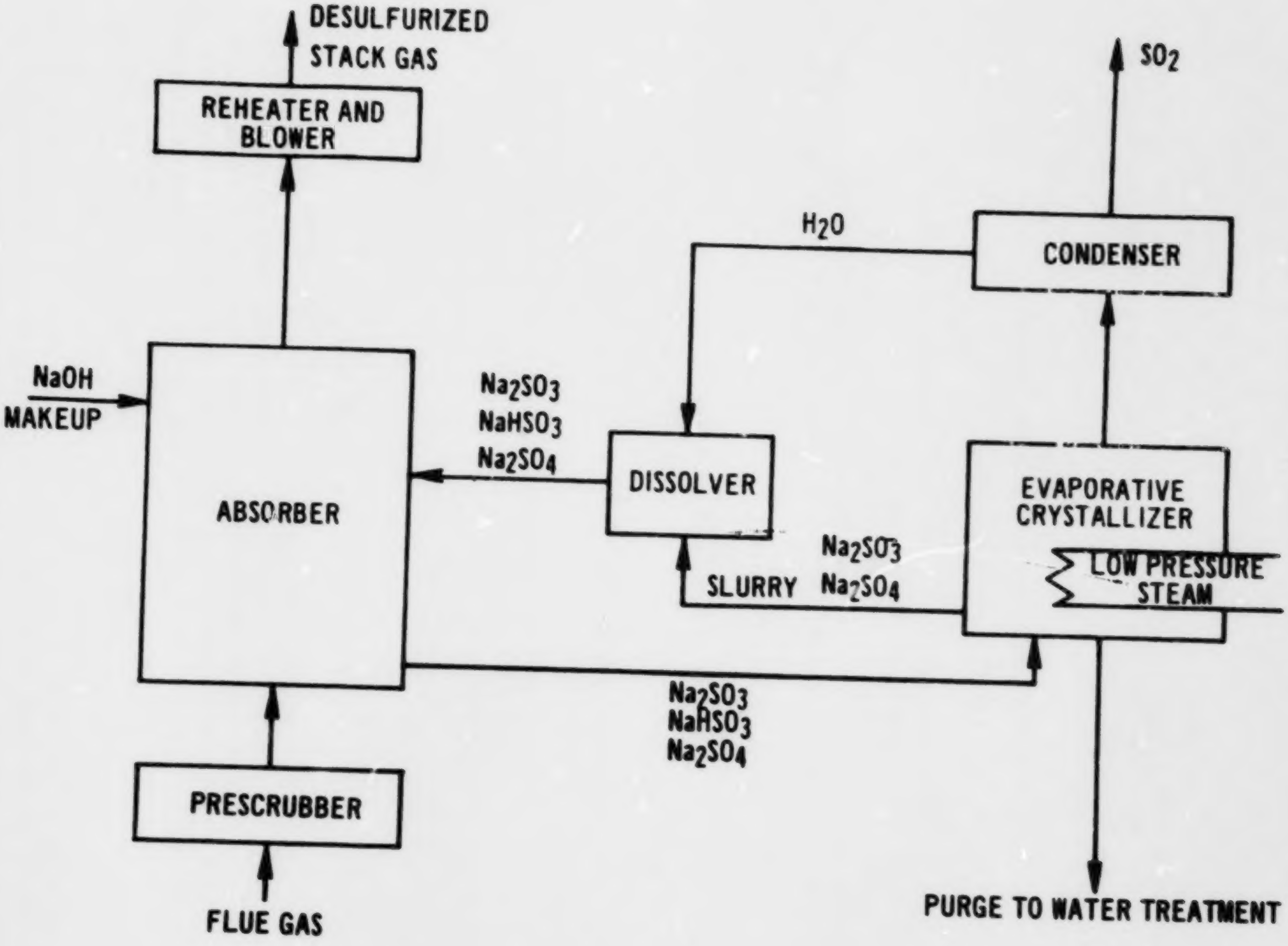

DESULFURIZED STACK GAS
REHEATER AND BLOWER
SO2
H2O
CONDENSER
NaOH MAKEUP
Na2SO3
NaHSO3
Na2SO4
ABSORBER
DISSOLVER
EVAPORATIVE CRYSTALLIZER
LOW PRESSURE STEAM
Na2SO3
Na2SO4
SLURRY
Na2SO3
NaHSO3
Na2SO4
PRESCRUBBER
FLUE GAS
PURGE TO WATER TREATMENT

Figure VII-11. Wellman-Lord process schematic.

of 1972. As a result of the performance of the unit, Standard has ordered three additional W-L Systems for other locations.

The largest unit in operation is on a 220-megawatt oil-fired utility boiler operated by Chubu Electric in Japan. This unit has been operating since May of this year with particular success in minimizing the quantity of sulfate purge by fractional crystallization of sodium sulfate from the absorber effluent liquor.

EPA has undertaken demonstration of the W-L System on a 115 coal-fired boiler at NIPSCO's D. H. Mitchell Station in Gary, Indiana. The capital cost of the system is being cost-shared on a 50-50 basis with the using utility, NIPSCO, and the demonstration year is scheduled to start in Spring of 1975. In the case of the EPA/NIPSCO demonstration unit, the W-L System will be mated with the Allied Chemical SO_2 Reduction Process to produce elemental sulfur. Allied Chemical will operate and maintain the W-L Allied System under contract with NIPSCO.

SO_2 Removal Efficiency

W-L Systems have obtained greater than 90 percent SO_2 removal efficiency for commercial systems operating for long periods of time.

Advantages and Disadvantages

The W-L process has several major advantages as follows:

(1) simplicity and reliability of the various unit operations involved

(2) when mated with the proper process, ability to produce elemental sulfur, or high grade sulfuric acid

(3) potential to achieve high efficiency SO_2 removal when required (95 percent or better)

(4) provided with surge capacity before and after the absorber to handle flue gas surges and to enhance system reliability

(5) the many applications and considerable operating experience provide a high confidence for success in future applications

Major process difficulties and disadvantages are:

(1) need to sell or dispose of a quantity of purge solids (sodium sulfate and other sodium salts)

(2) high energy demand results in derating of power station (3 to 6 percent)

(3) no coal-fired applications in operation

Performance and Reliability Summary

Operating W-L Systems have consistently achieved SO_2 removal efficiencies in excess of 90 percent for a wide range of SO_2 inlet concentrations. The most significant development efforts to date have been in the areas of reduced capital costs and minimization of purge requirement. As a result of process modifications which have now been proven in various operating systems, purge requirements of 5 percent or less of inlet sulfur can be anticipated.

Both the inherent high reliability of the equipment involved in the W-L process and the actual operating experience (97 percent on-stream factor over a 2 year period at the JSR boiler installation) point to an availability in excess of 95 percent. The high system reliability would be enhanced in large scale systems due to the opportunity for greater use of equipment spares and partial system operation as a result of multi-train configuration. The current practice of providing absorbent surge capacity permits short-term shutdown of the regeneration process without interruption of the scrubbing capability.

7.2.1.5 Catox Flue Gas Desulfurization Process

(See Figure VII-12)

The Monsanto Cat-Ox process utilizes catalytic oxidation to convert most of the SO_2 present in the flue gas stream to SO_3 for subsequent removal by an acid absorbing tower (followed by a fiber-packed mist eliminator to remove H_2SO_4 mist). For retrofit or "reheat" applications, the flue gases emerging from the boiler are passed through a high efficiency (99.6 percent precipitator)and then heated ("reheated") to 850°F as preparation for the catalytic oxidation step. The strength of acid produced in the absorbing tower is≈80 percent, which is primarily suitable for use in fertilizer production.

History and Experience

The Cat-Ox process was piloted on a 15 megawatt scale for 2 years commencing in August of 1967. Based on the successful pilot operation, agreement was reached in June 1970 between EPA, Illinois Power (IP), and Monsanto to install and operate a demonstration Cat-Ox system on a 110 megawatt coal-fired boiler at IP's Wood River Station at East Alton, Illinois. Construction of the system was completed in July of 1972 and after a considerable debugging period, the system was acceptance-tested in July 1973. However, because of the present lack of availability of natural gas, the reheat burners must now be modified to provide the capability for 100 percent firing on fuel oil. This has occasioned another delay which will preclude commencement of the year-long demonstration program until approximately April 1974.

SO_2 Removal Efficiency

During the acceptance test, the Illinois Power system achieved the emission control guarantees of 85 percent SO_2 removal and 99 percent

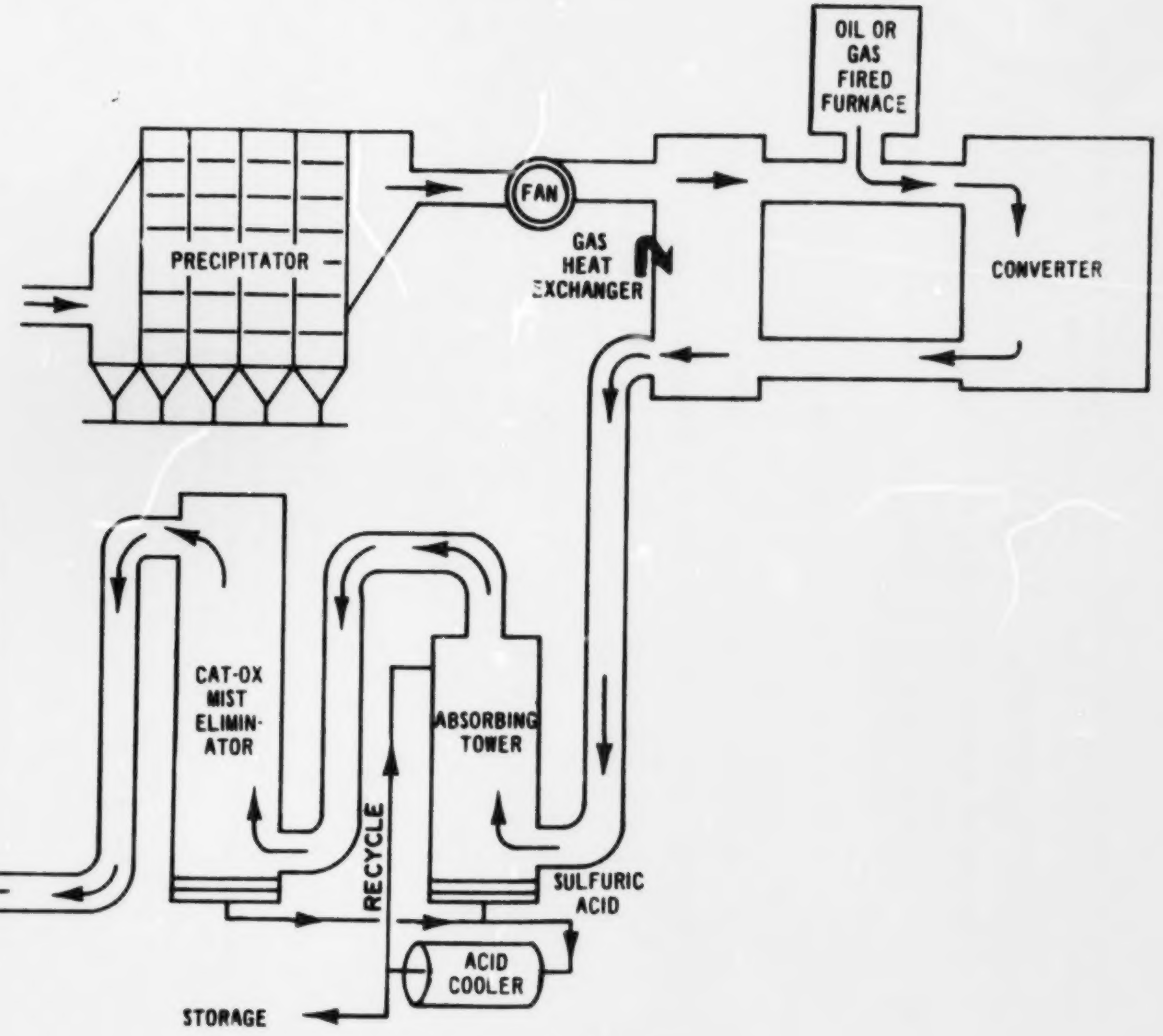

OIL OR GAS FIRED FURNACE
PRECIPITATOR
FAN
GAS HEAT EXCHANGER
CONVERTER
STACK
CAT-OX MIST ELIMINATOR
ABSORBING TOWER
RECYCLE
SULFURIC ACID
ACID COOLER
STORAGE

Figure VII-12. Reheat Cat-Ox process.

particulate removal. Removal efficiencies of greater than 90 percent are achievable with this technology for many applications.

Advantages and Disadvantages

The Cat-Ox Process advantages are as follows:

(1) Generates a product, which, in certain limited locations, can be disposed of by sale

(2) operating costs are relatively low

(3) achieves consistent 85 percent or better SO_2 removal over a wide range of SO_2 input concentrations

The major process difficulties and disadvantages are:

(1) Cat-Ox must be used near an appropriate acid user and dilute acid can be difficult to market in large quantities in some locations

(2) capital costs are high

(3) reliability and maintenance costs are not currently established due to a lack of operating experience

Performance and Reliability Summary

Work to date at the Wood River demonstration site has established the capability of the system to achieve 85 percent SO_2 removal; however, no information is available regarding system reliability or any possible performance degradation as a function of operating time. It should be noted, however, that the process and equipment are similar to the standard contact acid process and that major reliability uncertainties associated with the process center around the ability of the precipitator to provide adequate particulate removal to protect the catalyst bed.

7.2.2 Operational Reliability

If a FGD system is installed on a new or existing power plant, it must be able to give high availability to the plant. Extensive unavailability will mean either significant releases of pollutants to the atmosphere, fines imposed upon the utility, or power shortages to industry or to the community due to plant shutdown. None of these alternatives are desirable. There is some thought being given by vendors and the utilities industry to a dual control system. This system might consist of an ESP for reliable particulate control followed by a wet scrubber designed to achieve good SO_2 control. Therefore, if the wet scrubber is down for some reason, the power plant may still continue to achieve particulate control if it has to operate. The SO_2 emission limits will still be exceeded however.

Appendix A to this section of the report includes comments by various individuals regarding observations of operational FGD systems. Also, table VII-5 lists the problems experienced at some of these plants and the extent of the problem. It appears that to a large degree most of the problems to date have been mechanical or electrical rather than process. Data presented in Table VII-6 below shows that the APS Cholla station has experienced no process problems over a 4-month period.

Table VII-6

Operating Experience at APS Cholla Station

December 1973 - March 1974

Cause of Shutdown	Hours of Shutdown
Mechanical	241
Electrical	91
Process	0

The public hearings on the status of SO_2 control mentioned previously brought out three main reliability problems as expressed by the utilities industry - 1) chemical scaling in the scrubber, 2) demister plugging and wet/dry interfaces and 3) mechanical problems. It can be seen by tables VII-5 and VII-6 that operational experience at those plants listed does not substantiate the evidence of scaling and pluggage problems. Furthermore, a representative (6) of the Edison Electric Institute indicated during the hearings that "Many of those problems are well under way to having adequate solutions to them..." He also stated that "...in a well operated system in a well operated plant, plugging apparently has been overcome. Scaling is apparently well under way to being controlled."

In conclusion it appears that based upon the experience at a few selected plants (Mitsui, Louisville Gas & Electric, Boston Edison,

Table VII-5. FGD OPERATING PROBLEMS AND THEIR RESOLUTIONS AT VARIOUS PLANTS*

Problem	JSR Chiba Plant	Comm. Ed. Will County	Mitsui Chemico Plant	Boston Edison Mystic	EPA Shawnee	K.C.P&L LaCygne	Louisville G&L Paddy's Run
Chemical scaling	No	Minor	No	No	No	Minor	No
Demister pluggage	No	Yes	No	No	No	Yes	No
Wet/dry pluggage	No	No	No	No	No	No	No
Erosion/corrosion	No	Yes	No	Minor	Minor	Yes	No
Reheater problems	No	Yes	No	No	No	Yes	No
Mechanical problems (Fans, pumps, dryers, etc.)	No	Yes	No	Yes	No	Yes	Minor
Date started up	July 1971	Feb. 1972	Mar. 1972	Apr. 1972	Apr. 1972	Feb. 1973	Apr. 1973
Process	Wellman-Lord	Limestone	Lime	Magnesium oxide	Limestone & lime	Limestone	Limestone
Oil or coal	Oil	Coal	Coal	Oil	Coal	Coal	Coal
Size, megawatts	75	156	156	150	3x10 Mw	840	70
Testimony	S. Watt, Davy Powergas, pp. 2426-2450	B. Lee, Comm. Edison, pp. 2067-2206	H. Hesketh, So. Ill. Univ pp. 2741-2768	W. Irving Boston Ed., pp. 1356-1386	F. Princiotta EPA, pp. 35-110	D. McPhee, KCP&L, pp. 1436-1451	J. Mayrose LG&E, pp. 1198-1219

*Yes or No indicates whether problems were considered serious at time of hearing.

APS-Cholla, etc.) the types of problems identified by members of the utilities industry are being resolved. Solutions include the key aspects of - 1) high enough liquid to gas ratio, 2) high percentage of suspended solids in recycle slurry, 3) proper pH control, 4) careful design of wet/dry interface location, 5) proper scrubber type selection, and 6) consideration of delay tank to provide extended residence time in recycle loop.

7.2.3 Economics

Estimated installed costs of a scrubber system designed for high SO_2 collection efficiency are placed at about $40 per kw installed capacity for new plants and about $45 to $65 per kw for retrofit applications. (6) Table VII-7 presents detailed cost data on existing installations. Annual operating costs are estimated to range from 1.1 to 3.0 mills per kwh for new plants with an average of about 2.0 mills per kwh. The range for existing plants appears to be 2.5 to 4.0 mills per kwh. This compares with an average national consumer cost for power of about 18 mills per kwh. (7) These annual costs include depreciating the capital investment over a 15-year period on a straight line basis. A charge for the energy penalty of the scrubber is also included.

7.2.4 Installation Time Requirement

Testimony brought out in the public hearings (6) indicated a range from 27 to 48 months required to install a full scale FGD system. This time period goes from decision to install a FGD system to compliance with applicable emission regulations. The time requirements and witnesses are listed below in Table VII-8. Table VII-9 presents a further breakdown of the actual installations time requirements.

Table VII-8

FGD Installation Time Requirement

Experience of Witness	Time for Installation
Actual installation	27 to 36 months
EPA consultant	27 months
Utilities	36 to 48 months
Vendors	30 to 36 months

Table VII-7. CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Lime/Limestone systems - Retrofit							
---	Typical	200	52	2.4	Estimate	Assumes 80% load factor. Annual costs include facilities for waste disposal and environmental controls to minimize land and water pollution.	Princiotta, EPA, p. 55
Northern Indiana Public Service	Bailly 7,8	615	62	---	Estimate	Does not include sludge ponds (Not enough land for on-site disposal.)	Kuhlman, Sargent & Lundy (NIPSCo consultant), p. 589
Northern Indiana Public Service	Bailly 7,8	615	47	4-6	Estimate	Does not include sludge ponds. Capital investments required for sludge treatment included. Annual costs include fixation and hauling. 55% load factor.	Gerstle, PEDCo (EPA consultant), pp. 660-661

Table VII-7. (continued). CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Public Service Co. of Indiana	Wabash River	880	68	3.2	Estimate	Includes sludge disposal area facilities. 68% load factor.	Kolflat, Sargent & Lundy (PSI consultant), p. 703A
Public Service Co. of Indiana	Wabash River	880	66	3.7	Estimate	Sludge disposal included. Sludge pumping included in annual costs. 66% load factor.	Gerstle, PEDCo (EPA consultant), pp. 820–821
Detroit Edison	St. Clair	170	50	—	Estimate	Includes pond for sludge disposal but not the cost of land.	Willett, Peabody Engineering (Detroit Edison, vendor) p. 2282
West Penn Power	Mitchell	470	62	4	Estimate	Does not include sludge pond costs (pond is already constructed). Annual costs include sludge fixation and hauling. 70% load factor.	Gerstle, PEDCo (EPA consultant), p. 429

Table VII-7. (continued). CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Louisville Gas & Electric	Paddy's Run	70	57	---	Experience		Mayrose, LG&E, pp. 1242-1243
Public Service Co. of New Mexico	San Juan 1,2	670	45-60	---	Estimate		Geist, Pub. Service Co. of N. Mexico, pp. 1478, 1486
TVA	Widows Creek 8	550	76	---	Estimate		Seeber, TVA, p. 2318
Duquesne Light	Phillips	380	70-75	2.11	Estimate & experience	Annual cost does not include annualized capital costs.	Pernick, Duquesne Light, p. 1566
Commonwealth Edison	Will County 1	155	108	10	Experience	Includes sludge treatment. 35% load factor.	Lee, CommEd, pp. 2079-2080
Lime/Limestone Systems - New Plants							
---	Typical	1000	35	1.5	Estimate	Assumes 80% load factor. Costs include facilities for sludge disposal and environmental controls for land and water pollution.	Princiotta, EPA, p. 55

Table VII-7. (continued). CAPITAL AND ANNUAL COSTS FOR FGD SYSTEMS

COMPANY	PLANT	CAPACITY (Mw)	CAPITAL COSTS ($/kw)	ANNUAL COSTS (mills/kw-hr)	BASIS FOR COSTS	COMMENTS	WITNESS, AFFILIATION AND PAGE NUMBER
Kansas City Power & Light	LaCygne 1	820	42	---	Experience		McPhee, KCP&L, p. 1436
Ohio Edison	Mansfield	1600	93	2.7	Estimate	Capital costs include sludge disposal. Assumed 100% load factor.	Mansfield, Ohio Edison, p. 2170
Commonwealth Edison	Powerton 6	840	72-86	---	Bids		Lee, CommEd, p. 2079 Also in CommEd's written submittal dated 10-12-73 III-D-6
MgO Systems - Retrofit							
Boston Edison	Mystic 6	155	39	---	Estimate & experience	Includes cost of calciner facility but not of acid plant (acid plant is responsibility of chemical contractor)	Irving, Boston Edison, p. 1363
Cat-Ox Systems - Retrofit							
Illinois Power	Wood River	880	77	3	Experience (capital costs) Estimate (annual costs)	68.5% load factor.	Shultz, Illinois Power, pp. 1611-1612

Table VII-9

Actual Installations Timetable

Event	Time Required
Signed contracts	in 6 to 9 months
Construction begun	in 8 to 11 months
Startup	in 21 to 30 months
Compliance	in 27 to 36 months

7.3 NITROGEN OXIDES CONTROL

Nitrogen oxides form during the combustion process due to, 1) the nitrogen in the combustion air supply and 2) the nitrogen combined chemically in the fuel. In normal combustion conditions the only oxide of nitrogen formed is NO. Thermodynamic equilibrium dictates the formation of NO over NO_2. The formation of NO follows an exponential relationship increasing with temperature. Only about 5 to 10 percent (vol.) of NO_2 is formed during the combustion process. (3) Once emitted, however, from the stack, the NO may form NO_2 since it is in the presence of oxygen, i.e., air. Because formation of NO is extremely temperature dependent (see Table VII-10), it is apparent that any steps designed to reduce the combustion flame temperature will reduce the amount of NO emitted.

Table VII-10

Relative NO Concentrations

Flame Temperature, °F	Relative Concentration
2800	1.0
2900	2.0
3000	4.5
3100	9.0
3200	17.5
3300	30.0
3400	55.0

Most of these steps have been concerned with burner modification and burner design as well as tight control over amount of excess air.

7.3.1 Burner Modifications

There is some indication (3) that the physical location of the burner in the boiler has an effect upon the formation of NO. The location of the burners in the corner of the firebox (tangential firing) has shown in some tests to result in lower NO_x concentrations in the flue gas when compared to a boiler designed with burners located in the sidewalls (horizontal firing). More test data are being gathered to confirm or deny this observation.

The design of the burner appears to have some influence upon the formation of NO_x. For example the spud type burner results in higher NO_x emissions than the ring type burner. (3) It appears that a burner which produces a long lazy flame in contrast to a short intense flame favors lower NO_x emissions.

Burner spacing appears to affect the amount of NO_x emissions. A trend toward increased NO_x formation with decreased burner spacing has been observed.

7.3.2 Operating Condition Modifications

Low excess air combustion is one very potentially attractive method used to control NO_x emissions. This method is not without its disadvantages however. Very special precautions and careful attention must be placed upon the operation at a low excess air condition in order to prevent explosions, excess CO formation, excess visible emissions, and unburned fuel emissions. Operation at as close to stoichiometric conditions as possible is the principle of low excess air combustion.

A portion (10 to 20 volume percent) of the combustion air may be supplied by recycle flue gas. This technique, known as flue-gas recirculation, has the effect of 1) decreasing the flame temperature and 2) diluting the combustion air (oxygen) and the resulting flue gases. The flue gas may be introduced into the combustion zone by itself or in conjunction with the primary air.

The introduction of a portion of the combustion air above the primary burner ports can be effective in reducing NO_x emissions through flame temperature decrease. This technique is commonly known as two-stage combustion or overfire-air combustion.

Water or steam injection via atomizers located near the burner can effectively and substantially lower the flame temperature and, hence, NO formation. This technique carries with it the disadvantage of decreased boiler efficiency and higher corrosion rates.

7.3.3 Flue Gas Cleaning

Very little research and development work has provided favorable results from flue gas cleaning of NO_x. A pilot plant utilizing a wet scrubbing technique is generating some data on NO_x control at the Mojave plant.

7.4 CARBON MONOXIDE CONTROL

It is advantageous from an economic and efficiency standpoint, as well as from an environmental standpoint, for a utility to operate at a minimum of carbon monoxide emissions. The type of control for CO emissions is essentially that of good operating practice on the boiler. Sufficient air supply can insure minimal CO emissions formation. Design of the boiler to provide adequate residence time will result in minimal CO emissions. Short residence times tend to cause increased CO. At combustion temperatures higher than 2800°F some dissociation of CO_2 to CO will occur. Operation at temperatures near 2800°F favors minimal CO emissions. Good mixing provided by proper burner design will result in minimal CO formation. Finally, avoidance of flame contact with cold surfaces is desirable. A flame quenching and, hence, reduced residence time at effective oxidation temperatures may create excessive CO emissions.

7.5 HYDROCARBON CONTROL

Because hydrocarbons (HC) are the precursor, in conjunction with nitrogen oxides, of photochemical oxidant formation, it is desirable to achieve minimal HC emissions. When properly designed and operated, combustion equipment is not a large source of HC emissions and control equipment is not required. It is advantageous from a fuel efficiency standpoint for the operator of combustion equipment to insure that complete combustion takes place. The control techniques that are available include 1) good operating practice, 2) good equipment design and 3) fuel substitution.

7.5.1 Operating Practice

Hydrocarbon emissions are directly related to the three principles of combustion, i.e., 1) time, 2) temperature and 3) turbulence. A high degree of fuel and air turbulence leads to increased fuel combustion efficiency and hence decreased HC emissions.

7.5.2 Equipment Design

Improved combustion process designs will decrease the amount of HC emissions through increased fuel utilization. The trend toward better steam utilization in steam generating plants will also decrease relative HC emissions.

7.5.3 Fuel Substitution

Substitution of oil or gas for coal will result in lower HC emissions. This is a result of better mixing and firing characteristics of liquid or gaseous fuel compared to a solid fuel. Table VII-11 presents HC emissions for the three fuels as fired in a steam-electric plant.

Table VII-11

Steam-Electric Plant HC Emissions

Fuel	#HC/10^9 BTU Input
Coal	7.7
Oil	5.3
Gas	1.0

7.5.4 Auxiliary Control Equipment

If HC emissions from a fuel conversion facility are excessive, control equipment does exist to capture the HC. Principles of incineration, adsorption, absorption, and condensation have been successfully employed. These methods to date, however, have normally been used on small scale applications (low air flow) and are relatively expensive. The incineration technique may employ the use of a direct or catalytic afterburner to convert the HC to H_2O and CO_2. This technique pays a high energy penalty, as is indicated in Table VII-13. Adsorption of HC onto a charcoal filter, for example, has been practiced on a small scale. The control of motor vehicle evaporative HC emissions is an example of this technique.

The control of process HC emissions from a coal gasification plant will be necessary in order to meet ambient air quality standards. Acid gas from the gas purification unit is processed to recover the H_2S in the stream as elemental sulfur. However, light HCs remain in the gas stream. Techniques of incineration using auxillary fuel, catalytic conversion, and adsorption are being researched and advocated as the control system to reduce these HC emissions. These techniques can reduce the HCs to minimal quantities if they can prove reliable on the large-scale that is required.

7.6 CONTROL TECHNOLOGY SUMMARY

It may be helpful to put some of the previously discussed items into a summary type form. Therefore Table VII-12 presents pressure drop and particle collection efficiency for the five particulate collection devices which were discussed. Table VII-13 presents data which can be used to evaluate the energy penalty that must be paid upon the installation of a control device. Cost data are not available for describing the benefits accrued to the operator when employing "good operating practice" which subsequently leads to minimal HC, CO, and to some degree NO_x emissions. Table VII-14 presents capital and operating cost data for a few control devices. These data are subject to wide ranges and should be interpreted with care. Also, some of these figures are based upon rather old data.

Table VII-12 (1)

Particulate Collection

Typical Pressure Drops and Efficiencies

Unit	Pressure Drop in. H_2O	Efficiency Percent
1. Settling Chamber	0.5	20 - 60
2. Cyclones		
Large Diameter	0.5 - 4.0	30 - 65
Small Diameter	2 - 8	70 - 90
3. Electrostatic Precipitator	0.1 - 0.5	75 - 99.5
4. Wet Scrubbers	2 - 40	75 - 99.5
5. Fabric Filters	2 - 8	95 - 99.9

Table VII-13

Energy Requirements of Control Equipment (9)

	KW Equivalents/1000 scfm Gas Cleaned		
Control Equipment Efficiency	Low	Medium	High
Settling chamber	0	0	0
Centrifugal collector	0	0.49	0.78
Wet scrubber	0.97	2.61	11.18
Electrostatic precipitator	0.19	0.26	0.40
Fabric Filter	0.49	0.88	1.37
Afterburner		50 to 100	

Table VII-14

Economic Comparison

Equipment Type	Purchase Cost* ($/cfm)	Pressure Drop (in H_2O)	Power Used ($\frac{KW}{1000\ cfm}$)
A. Settling Chambers			
1. Simple	0.1	0.1-0.5	0.1
2. Multiple tray	0.2-0.7	0.1-0.5	0.1
B. Inertial Separators			
1. Baffle chamber	0.1	0.5-1.5	0.1-0.5
2. Orifice impaction	0.1-0.4	1-3	0.2-0.6
3. Louver type	0.1-0.4	0.3-1	0.1-0.2
4. Gas reversal	0.1	0.1-0.4	0.1
C. Cyclones			
1. Single	0.1-0.2	0.5-3	0.1-0.6
2. Multiple	0.3-0.7	2-10	0.5-2
3. Mechanical	0.2-0.7	--	0.5-2
D. Filters			
1. Tubular	0.3-2.3	2-6	0.5-1.5
2. Reverse jet	0.7-1.3	2-6	0.7-1.5
3. Envelope	0.3-2.2	2-6	0.5-1.5

(Continued)

* Steel construction, not installed, includes necessary auxiliaries, 1969 prices.

Table VII-14 (Continued)

Economic Comparison

Equipment Type	Purchase Cost (\$/cfm)	Pressure Drop (in H_2O)	Power Used $\left(\frac{KW}{1000\ cfm}\right)$
E. Electrical Precipitators			
1. One-stage	0.7-3.5	0.1-0.5	0.2-0.6
2. Two-stage	0.2-0.7	0.1-0.3	0.2-0.4
F. Scrubbers			
1. Spray tower	0.1-0.2	0.1-0.5	0.1-0.2
2. Jet	0.5-1.2	--	2-10
3. Venturi	0.5-1.4	10-15	2-10
4. Cyclonic	0.3-1.2	2-8	0.6-2
5. Inertial	0.5-1.2	2-15	0.8-8
6. Packed	0.3-0.7	0.5-10	0.6-2
7. Mechanical	0.5-1.4	---	2-10

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21. Pilot Plant Scrubber Tests to Remove SO_2 Using Soluble Alkali in Western Coal Fly Ash; Tufte, Sondreal, Korpi and Gronhovd; May 9, 1973.

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Appendix A

FGD Operational Experience - Comments

A. Operational Experience on U. S. Installations

Process: Boiler Injection of Limestone Followed by Wet Scrubbing
Process Supplier: Combustion Engineering
Constructor: Combustion Engineering
System Location: Union Electric Co., Meramec unit 2, St. Louis, Mo.
Start-Up Date: September 1968

SYSTEM DESCRIPTION AND HISTORY OF OPERATION

This 140 MW unit, the first full-scale utility SO_2 control system in this country, was officially shut down and abandoned in December 1971 approximately three years after its inception. This system consisted of two parallel single-stage marble bed absorbers equipped with demisters and reheaters. It was operated with some clarified liquor recycle.

The reason for abandonment was massive plugging and scaling in the entire boiler and SO_2 removal system. This recurrent problem barred the company from keeping the generating unit going for long periods. It has been said, however, that the up and down operation of the boiler necessitated by scrubber problems, due to the fact that no provisions for gas by-pass had been made, may have compounded the problems by causing moisture to combine with powdery deposits on the boiler tubes to form concrete-like deposits during periods of boiler shutdown. The implication is that boiler plugging might have been at least minimized by equipping the scrubber system with a bypass, thus allowing the boiler to operate independently of the scrubber, and less intermittently.

Process: Limestone injection in boiler with throwaway product.
Process Supplier: Combustion Engineering.
Constructor: Combustion Engineering.
System Location: Kansas Power and Light, Lawrence, Kansas, Units No. 4 & 5.
Startup Date: December 1968 and November 1971.

The 125 mw Unit No. 4, started up in December of 1968, was one of the first attempts to design a full size SO_2 scrubber. The limestone injection method was used. Multiple problems occurred during early stages of operation including corrosion, plugging of lines, and problems with reheaters and demisters. These problems did not include scaling. During the first four months of 1971, modifications in the original design enabled operation with some reliability.

When the scrubbers for the much larger 420 mw unit No. 5 started up in November 1971, the pond which was common to both units became overloaded and scaling occurred. Modifications in the design have been made that enable these chemical problems to be reduced but mechanical problems remain. At the present time, the modular arrangement enables the scrubbers to be cleaned without necessitating shutdown of the boiler.

The experiences at Lawrence have proved invaluable in making changes for later Combustion Engineering units such as the successful Paddy's Run plant. The Lawrence Station is, however, set in much of its design as a boiler injection system and in the closeness of the demisters to the absorbing bed. It, therefore, cannot fully benefit from the knowledge that has come from the operation of it and other systems.

Kansas Power and Light is able to operate a limestone SO_2 scrubbing system with significant SO_2 removal and some reliability while serving a large utility generating plant. This is a milestone in the development of SO_2 control technology.

Process: Limestone Scrubbing with Throwaway Product
Process Supplier: Babcock & Wilcox
Constructor: Babcock & Wilcox
System Location: Commonwealth Edison Co., Will County Station No. 1,
Romeoville, Ill., near Chicago
Start-Up Date: February 1972

SYSTEM DESCRIPTION AND HISTORY OF OPERATION:

Will County Unit 1 with scrubber on line, has a net power output of 156 MW. The system consists of two identical parallel wet limestone scrubbing trains, each consisting of a venturi for particulate removal, followed in series by a turbulent contact absorber (TCA) for SO_2 absorption. Each absorber and scrubber is equipped with its own recirculation tank. Spent slurry is bled to a clarifier which produces liquor for recycle via a 5 acre pond and a thickened sludge (underflow) which is pumped to a ready mix concrete truck where additives are mixed with the sludge in an attempt to make the sludge acceptable as landfill.

Since February 1972, the SO_x control systems have operated intermittently. Generally, SO_x removal efficiencies in the 80-90% range are attainable during periods of operation. Chemistry is not considered to be a problem with the system. Problems which have been responsible for shutdown of the system can be classified as mechanical, and were not all attributable to the SO_x control system. Some of the problems attributed to the limestone SO_x control system are: (1) demister and reheater pluggage; (2) wearing and plugging of spray nozzles; (3) reheater vibration and stress corrosion cracking; (4) plugging of slurry lines; (5) "sulfite blinding" of limestone and (6) scaling. Some of the other reasons cited for system outage are: (1) expansion joint failure; (2) inspection; (3) boiler outage; (4) motor failure; (5) contractor and operator errors; (6) fan trip; (7) water loss to pump glands; (8) fan damper operation; (9) leaks in slurry lines; (10) limestone supply and (11) booster fan vibration.

Solutions to almost all of the problems do not require development of new technology. Methods of controlling all of the problems specific to limestone wet scrubbing except for the reheater problems, have been used with some degree of success at Will County. Installation of inconel alloy reheater tubes is expected to solve the reheater stress corrosion cracking problem. Plugging is avoided by maintaining adequate flow of slurry. Scaling is controlled by circulation of high solids slurries and using adequate liquid/gas ratios. Demister pluggage is minimized by good demister wash techniques. Wear of nozzles is controlled by proper selection of materials of construction.

Between February and December 1972, the two SO_x control trains have accumulated in excess of 1400 and 1200 hours of operation respectively. During the outage periods many improvements and repairs were made. One of the trains has been shut down since April 1973 and presently is being cannibalized to support the other. Commonwealth Edison is attempting to iron out the problems with one train before attempting to operate both simultaneously.

Process: Magnesium Oxide Scrubbing with Thermal Regeneration
Process Supplier: Chemical Construction Corporation (Chemico)
Constructor: Chemical Construction Corporation
System Location: Boston Edison's Mystic Station
Everett, Massachusetts
Startup Date: April 1972

System Description and Operational History:

The MgO system which has been applied to the 150 MW oil-fired boiler at Boston Edison's Mystic Station utilizes a venturi scrubber to contact the magnesium oxide-magnesium sulfite slurry with boiler flue gases. The solids removed from the scrubber, rich in magnesium sulfite, are dried in a direct fired rotary dryer. The dried solids are shipped by truck to the Essex Chemical Company contact acid plant in Rumford, Rhode Island where the magnesium sulfite is calcined. The SO_2 produced by the calcining operation is converted to high grade sulfuric acid and the MgO produced is shipped back to Mystic Station for reuse in the absorber.

In April 1972, the shakedown period began for the Mag-Ox scrubbing system. The venturi scrubber has operated intermittently since then due to mechanical difficulties. During operation, the scrubber has achieved SO_2 removal efficiencies in excess of 90% with no apparent scrubber-related problems. The major problem has been with the design and operation of the $MgSO_3$ crystal dryer. Redesign of the dryer and a change of fuel to a low viscosity oil appear to be resolving these problems. Other problems with centrifuging the sulfite crystals from the scrubbing liquor and properly calcining the sulfite to regenerate MgO appear to be manageable. An availability factor of 85-90% was achieved for June and July of 1973.

This project is quite important because it will be the first time the individual steps of scrubbing, centrifuging, and calcining on an integrated basis for the Chemico process have been combined. Partially funded by EPA, the project involves not only the scrubber, centrifuge, and dryer at the Boston Edison plant but also the calcining and acid plants at Essex Chemical Company in Rumford, Rhode Island.

The first large scale coal-fired application was started up in September of this year at the Dickerson Station of Potomac Electric and Power. Flue gas from approximately 100 MW of the 195 MW of Dickerson Unit 3 will be processed. Since the plant burns coal (3% S, 8% ash), the scrubbing facility uses one venturi scrubber to remove the particulate and a second to remove the SO_2. Regeneration of MgO for this system will be carried out at the Essex Chemical facility which also serves the Boston Edison system.

Process: Cat-Ox
Process Supplier: Monsanto Enviro-Chem Systems, Inc.
Constructor: Leonard Construction Co.
System Location: Illinois Power Company, Wood River Station
East Alton, Illinois

Start-Up Date:

Construction was completed in July 1972 followed by debugging and modification. Acceptance testing was completed July 1973 with full operation to commence April 1974 following provision of additional modifications.

System Description and History of Operation:

The retrofit or "reheat" version of the Cat-Ox System has been installed on the 110 MW coal fired Wood River No. 4 boiler operated by Illinois Power. The process accepts flue gases from the discharge of a specially provided high efficiency ESP. The gases are heated to 850°F by heat exchange with processed gases from the catalytic converter and by supplemental "reheat" burners. The heated gases pass through the fixed bed catalytic converter where SO_2 is oxidized to SO_3. An acid absorbing tower followed by a fiber acid mist eliminator serve to remove the SO_3 prior to discharge of the flue gas to the stack. Product acid is cooled and stored in tankage.

Since its completion in July of 1972, a series of mechanical difficulties have occurred and modifications or repairs have been effected. During July of 1973 an acceptance test was conducted which established the capability of the system to achieve the specified 85% SO_2 removal while producing an acid product of somewhat greater than the required 77.7% concentration. Also, subsequent testing of the high efficiency ESP has established the particulate removal to be sufficient to prevent undue costs for catalyst cleaning. Long term operation of the system has been delayed until April of 1974 due to late delivery of equipment for a planned system modification to permit operation of the reheat burners on fuel oil rather than natural gas.

Process: Limestone scrubbing with throwaway product.
Process Supplier: Combustion Engineering.
Constructor: Combustion Engineering.
System Location: Kansas City Power and Light, Hawthorn Station, Units No. 3 and 4.

In September 1972, the 100 mw Kansas City Power and Light's Hawthorn 3 and 4 started up. Each of the boilers was originally equipped with a boiler injection system and two identical scrubber modules. Unit No. 4 has recently been converted to a tail-end system. Before changing to a tail-end system, boiler pluggage problems were experienced on Unit No. 4. Unit No. 3 still uses boiler injection and has not experienced boiler pluggage. No problems have been reported with the fans or reheaters on either unit. The remaining problems appear to be primarily with the recirculation system. Modifications similar to those used successfully at Combustion Engineering's scrubber at Louisville Gas and Electric Company's Paddy's Run plant show great promise of overcoming these problems. These include problems with headers and drain pots. Demister pluggage has been a problem but this appears to be solved. Some settling has occurred in the recirculation tank but this should be corrected with improvements in the agitation of the tank.

The method of ultimate sludge disposal has not been decided upon. Enough land area is available to enable them to pond the sludge for up to 15 years.

This plant is the last plant installed by Combustion Engineering using the limestone injection technique. Removal efficiencies have been between 70 and 80 percent.

Process: Limestone scrubbing with throwaway product.
Process Supplier: Babcock and Wilcox.
Constructor: Babcock and Wilcox.
System Location: Kansas City Power and Light, LaCygne Station, Unit No. 1.
Startup Date: June 1973.

The SO_2 scrubber at the new 820 mw LaCygne Station started operation in February 1973. The system consists of seven modules. At present, one module is controlling SO_2 and particulate with a venturi scrubber and a grid plate scrubber. The limestone is added to the scrubber rather than to the boiler.

The remaining six modules at LaCygne are controlling particulate only using the venturi section. The grid plate will be installed and limestone added at a future date to control SO_2 for the entire plant.

It is too early to accurately assess the reliability of this system since the boiler is new and has not become fully operational yet. The system is essentially a duplicate of the Will County scrubbing system and has experienced many of the same problems. These include plugging of the demisters, corrosion of the reheater tubes, and other mechanical problems. Like Will County, the problems are mechanical in nature and solvable using state-of-the-art methods. It is worthwhile to note that no chemical problems with the scrubber itself have occurred. It appears likely that the system will achieve reliable operation in the near future.

Unlike Will County, there are no bypass provisions at LaCygne, and no electrostatic precipitators are installed to collect particulate. The scrubbers are expected to achieve 80 percent control of SO_2 as well as satisfactory control of particulate.

One year hold time is available for sludge disposal. Plans beyond that time are uncertain.

Process: Lime Scrubbing with Throwaway Product
Process Supplier: Combustion Engineering
Constructor: Combustion Engineering
System Location: Louisville Gas and Electric Company, Paddy's Run
Station No. 6, Southwest of Louisville
Start-Up Date: April 1973

System Description and History of Operation:

The SO_x control system installed on this 70 MW electric generating unit consists of two parallel, two-stage marble bed scrubbers installed downstream of an electrostatic precipitator. The scrubber effluent liquor enters a large reaction vessel from which some spent liquor is bled to a thickener followed by a rotary drum filter. A carbide sludge slurry which contains lime as the active ingredient is fed to the reaction vessel. This absorbent slurry feed is controlled by a measurement of acidity in the system, and changes as necessary with variations in SO_x throughput. SO_x throughput varies with boiler-generator load and with variation of fuel sulfur content.

Between April and August 1973 the unit has accumulated about 1000 hours of operation. The scrubbers have operated for periods of up to 10-12 days with no problems. SO_x removal has been in the 90% range. There has been no evidence of scaling or plugging. Erosion/corrosion has not been a problem. There have been some minor mechanical problems.

The demisters, two stages of standard chevron, have not been a problem. Demister wash is accomplished once every eight hours with high velocity fresh water at the bottom of the demister. The amount of water used is only that amount needed to make up for normal evaporation and losses with the throwaway sludge. Thus, the system is operated as close to closed loop operation as can be expected.

The limited operation, overall, has not been due to problems for the most part, but due to the lack of operating manpower. During the peak demand periods, when all the Paddy's run units were on line, LG&E has had to shut the scrubber system down since operating manpower was spread thin and operation of the electric generating equipment took first priority.

B. Operational Experience on Japanese Installations

Process: Soluble sodium scrubbing with thermal regeneration (Wellman-Lord).
Process Supplier: Davy Powergas.
Constructor: Mitsubishi Chemical Machinery Company.
System Location: Japan Synthetic Rubber Company (JSR) near Chiba, Japan.
Startup Date: July 1971.

Successful reliable operation of the Wellman-Lord SO_x control process at Chiba with essentially 100 percent availability for over two years is considered quite significant for the U. S. control situation. This process consistently removes over 90 percent of the SO_2 from the exhaust gases of a 75 mw equivalent oil-fired boiler. The load is essentially constant but the concentration of SO_2 varies from 400 to 2000 ppm.

It appears that the process should be applicable to coal-fired boilers if fly ash removal equipment is installed upstream of the absorber. A Northern Indiana Power Service Company (NIPSCO) unit, partially funded by EPA, will evaluate such systems on a coal-fired boiler. Cost studies indicate that capital and operating costs for a Wellman-Lord system in the U. S. on a coal-fired boiler are not a great deal higher than those for wet lime/limestone or magnesium oxide scrubbing systems, which are generally considered the least expensive of the flue gas desulfurization systems. The system is commercially offered and guaranteed in the U. S.

The major problem with the process is the requirement for a bleed to remove contaminants, primarily sodium sulfate (Na_2SO_4). Present information indicates about 10 percent of the total incoming sulfur is lost as soluble Na_2SO_4 at Japan Synthetic Rubber (JSR).

Sodium sulfate is a natural component of sea water but could possibly cause problems in fresh water. This purge has been substantially reduced at the newer installation at Chubu Power and may be further reduced by oxidation retardants research by Sumitomo.

The product of the Wellman-Lord system at JSR is high-purity sulfuric acid. While there may be insufficient markets for the sulfuric acid produced if a large percentage of the plants in the U. S. used this method, there is probably a market available for the output of several plants, particularly those in eastern and midwestern industrial areas.

Elemental sulfur, which will be produced in the NIPSCO unit, is another potential product which is both storable and potentially saleable; this could ultimately be a more desirable end product, especially for utilities not near a market for sulfuric acid. A disadvantage of elemental sulfur production is the necessity of the use of considerable quantities of a reducing agent such as coke or natural gas.

Process: Lime scrubbing with throwaway product.
Process Supplier: Chemical Construction Company (Chemico).
Constructor: Mitsui Miiki Machinery Company.
System Location: Mitsui Aluminum Company, Omuta Power Station, Japan.
Startup Date: March 1972.

The scrubber at Mitsui Aluminum's Omuta Power Station began operation on March 29, 1972. The system uses as an absorbent carbide sludge that is chemically identical to lime with regard to SO_2 scrubbing. The scrubber serves a coal-fired 156 mw boiler that burns coal equivalent to about 2.5 percent sulfur eastern or midwestern U. S. coal. The scrubber has had several load variations similar to, albeit less frequent than, typical U. S. boilers. The system has operated at closed-loop conditions for substantial periods of time and is open loop only occasionally during periods of heavy rain. Fly ash concentration into the scrubber is similar to that for typical U. S. retrofits.

The system has obtained 18 months of continuous, essentially trouble free, operation since startup.

It should be noted that the reliable performance of this system is of real significance to the United States air pollution control program, since the design ground rules for the Japanese unit are quite similar to those of many of our power utilities requiring desulfurization systems. The following are among the areas of commonality: retrofit of existing coal-fired boiler, moderately efficient electrostatic precipitators, installation on moderately-large size boiler, production of a throwaway product, and availability of lime (calcium hydroxide). The unit takes on additional significance since the system was designed based on U. S. technology (Chemico) and is offered and guaranteed in this country. Two similar units using lime on coal boilers are being constructed in the U. S. for Duquesne Light Company's Phillips Station and Ohio Edison's Bruce Mansfield Station.

Process: Sodium Scrubbing with Thermal Regeneration (Wellman-Lord Process)
Process Supplier: Davy Powergas, Inc.
Constructor: Mitsubishi Chemical Machinery (MKK)
System Location: Chubu Electric
Nagoya, Japan
Startup Date: May 1973

System Description and History of Operation:

The Chubu system is applied to a peaking service, oil-fired utility boiler of 220 MW output. The system utilizes a rectangular sieve tray absorber which has maintained SO_2 outlet levels consistently below 150 ppm. Double effect evaporation is utilized for regeneration and a purge crystallization system is provided to minimize sodium loses through purge. The purge crystals have assayed higher than 85% sodium sulfate. The system is designed to treat flue gas from burning of 4% sulfur and to handle changes in boiler load from 25% to 100%. Because of the peaking service application, the system is subjected to frequent weekend shutdowns with no restart problems encountered to date. It is noteworthy that at one point during the recent testing program the boiler fuel was changed from 0.7% sulfur oil to 4% sulfur oil instantaneously through boiler operator error. In spite of this many-fold step change in inlet concentration, outlet concentration of SO_2 remained below 150 ppm.

SECTION VIII

METHODOLOGIES FOR ASSESSING VISIBILITY

8.1. INTRODUCTION

The relationship between increased quantities of man made pollutants injected into the atmosphere and visibility is an issue that will confront the Northern Great Plains decision makers in their attempt to evaluate the environmental impacts stemming from the operation of large power and gasification plants and concomitant secondary development. Emissions of particulate matter, sulfur dioxide, nitrogen oxides and hydrocarbons could conceivably threaten the "Big Sky" region's common 75 + mile visibility. Although reduced visibility can hamper ground and air transportation, it is the aesthetic impact on this rural environment that might prove to be the most serious to the residents of the area, as well as tourists.

The development of strategies to control, minimize or prevent human-caused visibility reductions must be preceded by the development of reasonably systematic, quantitative, unambiguous and reproducible methods of documenting visibility. This section examines several state of the art approaches to measuring visibility, some of which are to be used next year at one or more sites in the NGPRP study area. Baseline visibility data would then be recorded under a variety of atmospheric and meteorological conditions. It is desired (Section X, Research Needs) to continue monitoring for a substantial period of time to assess the state of visibility in the region both before and after energy conversion facilities become operational.

This section will discuss pertinent physical concepts and visibility measurement methodologies.

8.2. SOME PHYSICAL CONSIDERATIONS

The Glossary of Meteorology (1959) defines visibility as:

> the greatest distance in a given direction at which it is just possible to see and identify with the unaided eye (a) in the daytime, a prominent dark object against the sky at the horizon, and (b) at night, a known and preferably unfocused, moderately intense light source. After visibilities have been determined around the entire horizon circle, they are resolved into a single value of prevailing visibility for reporting purposes.

Generally, four factors determine how far an observer can see:

(a) The optical properties of the atmosphere. These properties determine the behavior and fate of visible light radiation as it travels through the atmosphere. Chemical composition, size, density, shape, phase (liquid, solid, gas) of atmospheric constituents all help to define the optical properties.

(b) The amount and distribution of light, e.g., natural or artificial light sources providing uniform or nonuniform illumination.

(c) The characteristics of the object that an observer attempts to see, e.g., color, shape, extent and whether it is a self-luminous object or only a source of reflected light.

(d) The properties of the human eye.

The optical properties governing the transmission of light are the most significant of the four for this discussion and warrant further treatment.

Light is diminished by two optical processes as it propagates through the atmosphere--scattering and absorption. Scattering is the phenomenon by which molecules and aerosol particles interact with incident light and spatially redistribute it in other directions. Aerosol particles are taken here to mean dispersed solid and liquid matter whose individual entities range in diameter from .0002 microns (molecular size) to approximately 500 microns (Air Quality Criteria for Particulate Matter, 1969). (One micron is one millionth of a meter). The second process, absorption, is the actual removal of the light by the atmospheric constituents.

Our ability to perceive an object is a function of its relative contrast, or the difference in light received from the object and its background. Absorption and scattering diminish the contrast by reducing the light received from both the background and the object of interest. In addition, the scattering of "sky light" into the observer's field of view reduces the contrast further and lightens distant objects, e.g., distant mountain ranges appearing blue.

Mathematically, this attenuation of light as it travels through a path length X of atmosphere can be written (Middleton, 1958) as

$$I = I_0 e^{-\sigma x} \qquad (1)$$

where I_0 = initial intensity of light

I = intensity of light after traversing a path length of length x

σ = total extinction coefficient

e = base of natural logarithms, 2.71828...

The total extinction coefficient can be split up into terms representing the contributions from four processes:

$$\sigma = b_{scat} + b_{Rayleigh} + b_{\substack{abs \\ molecule}} + b_{\substack{abs \\ aerosol}} \qquad (2)$$

where b_{scat} = contribution to extinction resulting from scattering by aerosol particles

$b_{Rayleigh}$ = represents the extinction caused by scattering by air molecules (Rayleigh scattering)

$b_{\substack{abs \\ molecule}}$ = extinction due to absorption by gaseous molecules, such as NO_x, and H_2O.

$b_{\substack{abs \\ aerosol}}$ = extinction due to absorption by aerosols, such as soot.

The relative magnitudes of these four coefficients vary and will be discussed later. However, Rayleigh scattering is usually much less important than aerosol scattering (Middleton, 1958). Aerosol scattering is described by Mie scattering theory, a theory explaining light scattering by particles whose size is comparable to the wavelength of the incident light (approximately one micron).

Visibilities of 150 miles would be possible if Rayleigh scattering were solely responsible for light extinction (Robinson, 1968). Absorption can be as significant a cause of extinction as scattering in urban areas with soot and haze. (Robinson, 1968)

8.3. DETERMINATION OF VISIBILITY

The approaches investigated here focus on the measurement of total light extinction and light scattering.

8.3.1. Total Extinction

Koschmieder (1924) (English treatment, Middleton 1958) developed a theoretical relationship between the extinction coefficient and a quantity referred to as the visual range, which is defined as the distance at which a large ideal black object can just be discerned in a horizontal direction against its background under daytime conditions. This relationship can be expressed symbolically as

$$L_v = \frac{\ln (1/\epsilon)}{\sigma} \qquad (3)$$

where L_v = visual range, (meters)

σ = extinction coefficient (meters^{-1})

ϵ = limiting contrast between a large object and its background that an observer can perceive

A homogeneous atmosphere is assumed, hence a constant extinction coefficient is used. A value of 2% or .02 is usually taken for the limiting contrast. The visual range in this case (also called the meteorological range) becomes

$$L_v = \frac{\ln (1/.02)}{\sigma} = \frac{3.9}{\sigma} . \qquad (4)$$

Visual range is not the same quantity as prevailing visibility, which is a composite value for the entire horizon. Rather, L_v is determined from the observation of extinction at a single point, or more realistically, within a small volume of atmosphere surrounding the visibility sensing device.

8.3.1.1. Transmissometers

A device that measures the extinction of light as it passes through a sample of atmosphere is the transmissometer, represented in Figure VIII-1. This double ended instrument has a light source and a sensitive light detector at opposite ends, enabling a comparison to be made between the intensities of the incident and attenuated light beams.

If

I_0 = incident light intensity, and

I = light intensity recorded at detector after light travels across the instrument baseline, b

then the extinction, T, can be defined as

$$T = \frac{I_0 - I}{I_0} = 1 - \frac{I}{I_0} .$$

Using (1) and (3), the extinction can be expressed as:

$$T = 1 - e^{-\sigma b} = 1 - \exp\left\{-\left[\ln {}^{1/\epsilon}/L_v\right] b\right\}$$

$$= 1 - \exp\left\{\ln \epsilon^{b/L_v}\right\}$$

$$= 1 - \epsilon^{b/L_v}$$

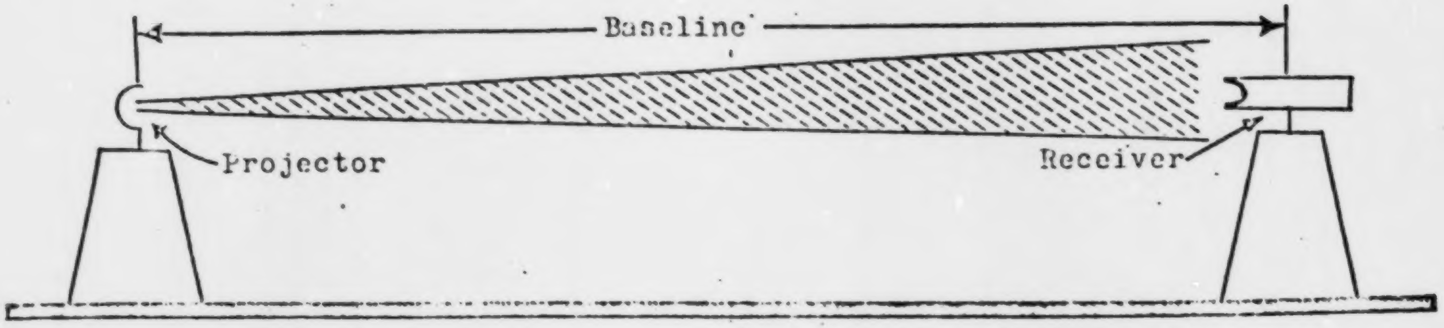
Baseline
Projector
Receiver

Figure VIII-1. Transmissometer (From George and Zeller (1973))

Thus, knowing the threshold contract ϵ, the baseline (see Figure VIII-1) distance b, and measuring T with the transmissometer will determine the visual range, L_v.

Transmissometers require relatively long baselines (150 meters, for example); sturdy installation; and careful alignment of light source and detector. The instrument provides stable, accurate and precise measurements based on theory that has been experimentally verified. Transmissometers are relatively expensive (in the vicinity of $10,000), however, and have primarily been employed to quantitatively assess low visibilities (less than 10 km) produced by fog, snow, smoke, dust, etc., in urban and non-urban areas.

8.3.1.2. Photographic Documentation of Visibility

A photographic approach to documenting visibility was described by Steffens (1949), and adapted recently by Dames and Moore (1974). The extinction coefficient and hence, visual range, is measured by photographing a distant object and measuring the image contrast between the object and its horizon sky. The film image densities of the object and horizon are used with the film characteristics and object distance to calculate the visual range.

From equation (3), the visual range of an ideal black object in a homogeneous, uniformly illuminated atmosphere is

$$L_v = \left[\ln \frac{1}{\epsilon}\right] / \sigma$$

For non-black reflecting objects (3) may be rewritten (Dames and Moore) as

$$L_v = \left[\ln \frac{1}{\epsilon}\left(1 - \frac{I_o}{I_\infty}\right)\right] / \sigma \qquad (5)$$

where I_o = the intensity of light reflected by the object. I_o may be expressed as $I_o = A_o I_i$ where I_i is the intensity of light incident on the object and A_o the fraction of the incident light reflected from the object's surface (reflectance).

I_∞ = light intensity of the background horizon adjacent to the object.

The extinction coefficient, σ, can be expressed in terms of the contrast between a large object and its horizon sky. Equation (1) can be rewritten as

$$(I_x - I_\infty) = (I_o - I_\infty)\exp(-\sigma x)$$

with x as the distance between an observer (or camera) and the object in question. Rearranging the above expression one finds that:

$$\sigma X = \ln\left\{\left(1-\frac{I_o}{I_\infty}\right)\Big/\left(1-\frac{I_x}{I_\infty}\right)\right\} \qquad (6)$$

Solving for σ and inserting the result into (5) yields:

$$L_V = x\,\frac{\ln\left\{\frac{1}{\epsilon}\left(1-\frac{I_o}{I_\infty}\right)\right\}}{\ln\left(1-\frac{I_o}{I_\infty}\right)-\ln\left(1-\frac{I_x}{I_\infty}\right)} \qquad (7)$$

The method of determining visual range thus consists of inserting values of X, ϵ, I_0/I_∞ and I_x/I_∞ into (7) and solving for L_V.

A specific site (or sites) is chosen from which visual range measurements are to be made. The camera view is selected to contain a large, stationary distant object, (for example, a mesa or mountain) that is readily distinguishable. This view is then photographed on a regular basis using black and white film and a telephoto lens. X, the distance between the distant object and camera, is known beforehand from topographic maps, etc. The contrast threshold, ϵ, can be assumed to be .02.

I_x/I_∞ is determined photometrically from the film. It is accomplished by measuring the image contrast on the negative between the object and its horizon sky using a transmission densitometer, which relates the light transmitted through the film to the film's density. Image densities measured by the densitometer are calibrated by exposing each film strip to a standard grey scale step wedge. From this calibration information, the ratio of the intensities I_x/I_∞ is computed from the image densities of the object and its adjacent horizon sky.

For many dark objects, it can be shown that the ratio $\frac{I_0}{I_\infty}$ equals one half the reflectance, A_0. A reflectance of .25 can be assigned to the dark objects since it is the reflectance of rough dry earth. Therefore,

$$\frac{I_o}{I_\infty} = \frac{.25}{2} = .125$$

and equation (7) can now be solved for L_V, the visual range. The above relationship involving I_0, I_∞ and A_0 is valid for dark objects only. Snow covered objects, with much greater reflectances, cannot be accurately used in this methodology. However, the extension of this theory to allow the consideration of highly reflective objects is presently being investigated (Biggs, 1974).

This technique for measuring visual range requires a minimum of field equipment. However, the lack of reliable automated photographic equipment requires a technician to operate and maintain the cameras; to assure proper exposure parameters; to keep records on photographic, physical and meteorological conditions; and to mail exposed film back to a laboratory for processing and densitometer evaluations. Other visibility methodologies use instruments, e.g., the transmissometer, and nephelometer (see section 8.3.2), which require far less human supervision. These instruments also have the capability of recording data continuously as opposed to the intermittent data collection of the cameras.

Unlike several other methodologies described in this section, this photographic approach has already been used to assess long range visibilities (150 km) in rural undeveloped areas. Furthermore, this approach does not employ localized observations, but rather observations integrated over the entire line of sight.

8.3.2. Total Scattering

In the absence of smokes of obvious colors, soot, and industrial hazes, absorption becomes less significant and light extinction by scattering predominates (Robinson 1968). Hence, under this assumption equation (2) degenerates to an expression for the scattering coefficient b:

$$\sigma = b_{scat} + b_{Raleigh} \equiv b \qquad (8)$$

For urban conditions b_{scat} is typically much greater than $b_{Raleigh}$ (Robinson 1968) because of increased numbers of aerosol scattering particles. Thus, aerosol scattering can be assumed to be the primary factor in light extinction. Lower concentrations of particulate matter in rural areas imply that $b_{Raleigh}$ and b_{scat} could be comparable and b, rather than b_{scat}, would better describe light attenuation.

The visual range (equation #4) can be written as

$$L_v = \frac{3.9}{b} \qquad (9)$$

where L_v and b have consistent units (e.g., meters and meters^{-1}). Equation (9) implies that measurements of the scattering coefficient will give information on the visual range. The scattering coefficient hereis a measure of the total light scattering in all directions when an initial intensity of light is transmitted through a volume of the atmosphere. Total scattering is distinguished from forward and backscattering (section 8.3.3, 8.3.4 respectively) where only that portion of incident light scattered towards a particular direction is considered.

The integrating nephelometer, invented by Beuttell and Brewer (1949) and refined by Ahlquist and Charlson (1967, 1969) measures the total scattering coefficient. A small sample of air is continuously drawn into a chamber (Figure VIII-2) with a special geometric configuration. A flash lamp periodically illuminates the air sample, which then scatters the light, some of which is incident on the face of a photomultiplier tube. The geometric configuration of the chamber is such that the quantity of light reaching the tube is proportional to the scattering coefficient, integrated over all scattering angles (directions). The nephelometer developed by Charlson and Ahlquist has sufficient sensitivity to measure the Rayleigh scattering contribution from particle free gases. Thus, both $b_{Rayleigh}$ and b_{scat} can be measured in the local neighborhood of the instrument.

Horvath and Noll (1969) investigated the relationship in urban areas between the prevailing visibility determined by human observers and b_{scat} as measured by the nephelometer. Their results indicated a large correlation between the observed visibility and b_{scat} implying a relationship similar to that between L_v and b_{scat} (Equation 4). Results from several sites and observers were within 25% of the predictions of equation (4) when relative humidity was less than 70%.

A State of California Air Resources Board study (1973) also indicated a large statistical correlation between prevailing visibility observations and b_{scat} measurements at three large cities. These results indicate that aerosol scattering was primarily responsible for visibility reduction and that the assumption of b_{abs} being negligible was valid. The high correlation coefficients of prevailing visibility to b_{scat} is interesting since b_{scat} is a point measurement, while the visibility is an integrated measurement over a long path length. This result tends to minimize the importance of spatial variations of b_{scat} affecting the prevailing visibility.

The correlation between b_{scat} and prevailing visibility would be expected to be good in urban areas with many area and point sources contributing to the air quality. The distribution of pollutants is more uniform with many area and point sources, and the probability of obtaining a small air sample which is representative of the area is great. However, in a rural area with perhaps only one large continuous elevated point source contributing to air quality, the correlation between b_{scat} and prevailing visibility will depend on how evenly distributed is the plume. Sampling through the plume would give a large extinction (poor visibility indication) when, in reality, the prevailing visibility away from the plume is very good.

Considerable effort has been directed at the relationships, if any, between the aerosol particulate matter mass concentration and both the scattering coefficient (as measured by the nephelometer) and visual range. (Charlson, et. al. (1968); Charlson (1969); Ettinger (1971); Noll, et. al. (1968); State of California Air Resources Board (1973)).

Such relationships would prove to be extremely useful because they would predict visibility (or visual range) as a function of

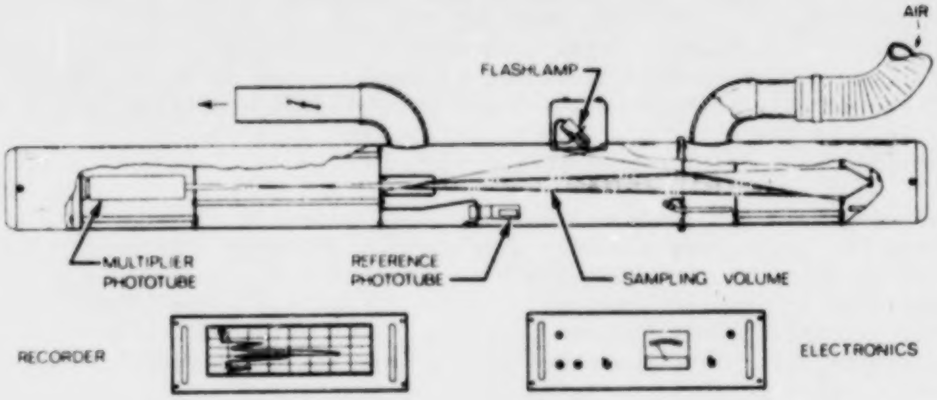
AIR
FLASHLAMP
MULTIPLIER PHOTOTUBE
REFERENCE PHOTOTUBE
SAMPLING VOLUME
RECORDER
ELECTRONICS

Figure VIII-2. Integrating Nephelometer (From Tombach (1971))

ambient air concentrations of suspended particulate matter. Consequently, the contributions to visibility degradation from large pollutant sources could be quantified once the sources' effects on the ambient concentrations of pollutants were known.

Results of the work of Charlson, et. al. (1968); and Noll, et. al. (1968) based on low humidity urban observations indicate a direct proportionality between aerosol mass concentration and light scattering. The empirical expression between these two quantities was found to be (Charlson (1969)):

$$\frac{M(ug/m^3)}{b_{scat}(m^{-1})} = 4.5\,^{+\,4.5}_{-\,2.2} \times 10^5\ \mu g/m^2$$

$$= 0.45\,^{+\,0.45}_{-\,0.22}\ \ g/m^2 \qquad (10)$$

where M represents the aerosol mass concentration and b_{scat} is as defined above. The 90% confidence limits are indicated as the superscript and subscript. Using this result with the Koschmeider expression for visual range (equation 4) Charlson (1969) has produced an empirical expression for the relationship between visual range and mass concentration:

$$L_v(m) = \frac{3.9}{b_{scat}(m^{-1})} = \frac{3.9(4.5\,^{+\,4.5}_{-\,2.2} \times 10^5\ \frac{\mu g}{m^2})}{M(\mu g/m^3)}$$

$$L(m) = \frac{1.8\,^{+\,1.8}_{-\,0.9} \times 10^6}{M(\mu g/m^3)} \qquad (11)$$

Expressing L_v in kilometers, (11) becomes

$$L_v(km) = \frac{1.8\,^{+\,1.8}_{-\,0.9} \times 10^3}{M(\mu g/m^3)} \qquad (12)$$

The mass visibility relationship cannot be used indiscriminately. Theoretical work (Air Quality Criteria for Particulate Matter, 1969) indicates that this expression should be applicable under the following conditions:

1. The aerosol size distribution should always have the same form or shape, that of a power law such as described by Junge (1963) where the size distribution is described mathematically as

$$\frac{dN}{d\ ln\ r} \sim r^{-\,(3.5\,\pm\,.5)}\ ,$$

where N = # particles/unit volume

r = radius of particle.

Well aged and distributed aerosols in the lowest region of the atmosphere, over urban or rural areas, tend to exhibit such a size distribution. It appears that this distribution is not applicable for freshly formed aerosols, e.g., smoke plumes from isolated single sources.

2. The relative humidity should be less than 70%. Greater relative humidities encourage the formation of condensation nuclei. Deliquescence is a function of chemical composition and size of aerosols, as well as relative humidity. This makes it difficult to determine a mass concentration - visibility relationship without detailed information on the chemical composition of the aerosol as a function of particle size.

3. Koschmeider assumed a homogeneous atmosphere with a constant extinction coefficient along the line of sight. b_{scat} and M are measured at a single point. Hence the applicability of the L_v-M relationship rests on the degree of atmospheric homogeneity.

Additional experimental tests of the validity of equations (10) and (11) have been made. Ettinger (1971) reported that non-urban aerosol mass concentration and scattering coefficient (determined by the nephelometer) data taken at Los Alamos, New Mexico fitted an empirical equation in close agreement to (10) which was based on urban observations. Thus, the b_{scat}-M relationship might be consistent for high and low pollution conditions.

Noll, et. al. (1968) concluded that it was possible to estimate within ± 50 percent the visibility from averaged mass concentration data as per equation (11). However, the State of California Air Resources Board Study (1973) study of visibility, light scattering and aerosol mass concentration at three California cities documented a poor correlation between prevailing visibility and mass concentration of particulate matter.

In conclusion, the nephelometer is one approach to quantitatively assessing visibility that must be considered. It is relatively inexpensive (on the order of $5,000) and is highly mobile. However, it samples the air only within close proximity of itself, and it is from these point source measurements that information on long range visibility must be inferred. Consequently, considerably more research must be directed towards the use of this instrument in rural areas to experimentally verify the relationships between:

1. Prevailing visibility and visual range (L_v) under various meteorological conditions.

2. Prevailing visibility and total light scattering (b_{scat}).

3. Total light scattering and prevailing visibility.

4. Aerosol mass concentration and prevailing visibility.

5. Varying physical properties of aerosols and its influence on the above relationships.

6. The magnitude of aerosol scattering relative to aerosol absorption and molecular scattering and absorption.

8.3.3. Forward Scattering

Forward scattering visibility instruments sense the light energy scattered in the forward direction when a known amount of light energy is transmitted through a volume of atmosphere. Figure VIII-3 is a schematic representation of this device. Forward scattered light can be empirically related to light extinction and visual range. George and Zeller (1973) indicate a general relationship of the form

$$L_v = \frac{\epsilon\, c(f)}{\sigma} \tag{13}$$

where c(f) is an instrument related constant, ϵ a detector threshold and σ , the extinction coefficient determined from forward scattering measurements. Equipment costs are relatively expensive ($10,000 per instrument). The baseline separation between the source and detector is small, on the order of a few feet. The key to the instrument's utility, as with the nephelometer, lies in how representative are the short baseline measurements of a longer path length under varying meteorological conditions. Recent work (Hering, et. al., 1971) has focused on short range (few kilometers) visibility determinations.

8.3.4. Backscattering

The backscattering measurement technique employs a high intensity light pulse projected into the atmosphere and a photoelectric receiver alongside to measure that part of the original light pulse scattered in the backward direction, as illustrated in Figure VIII-4.

Fenn (1966) and Vogt (1968) reported that theoretical considerations produce no generally valid relationship between the extinction coefficient and atmospheric backscattering. Natural processes which modify the size of the aerosol particles, and their size distribution give rise to different extinction-backscattering relationships. These relationships are further complicated by their dependence on the wavelength of the scattered light. However, in many cases an expression of the form:

$$L_v = \frac{C}{S^{1.5}} \tag{14}$$

is useful, where C is a constant and S is the strength of the detected backscattered light signal. Curcio and Knestrick (1958) determined that

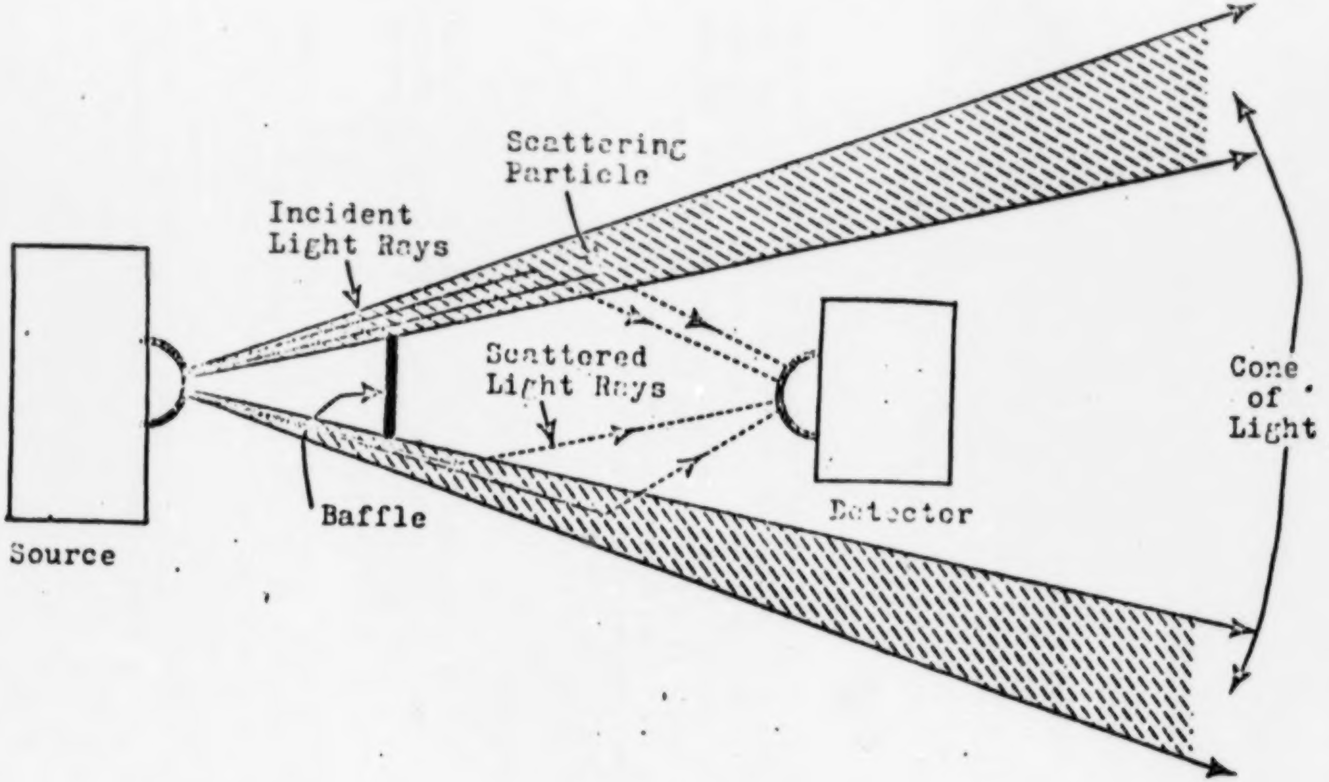
Scattering
Particle
Incident
Light Rays
Scattered
Light Rays
Cone
of
Light
Baffle
Source
Detector

Figure VIII-3. Forward Scatter Device (From George and Zeller (1973))

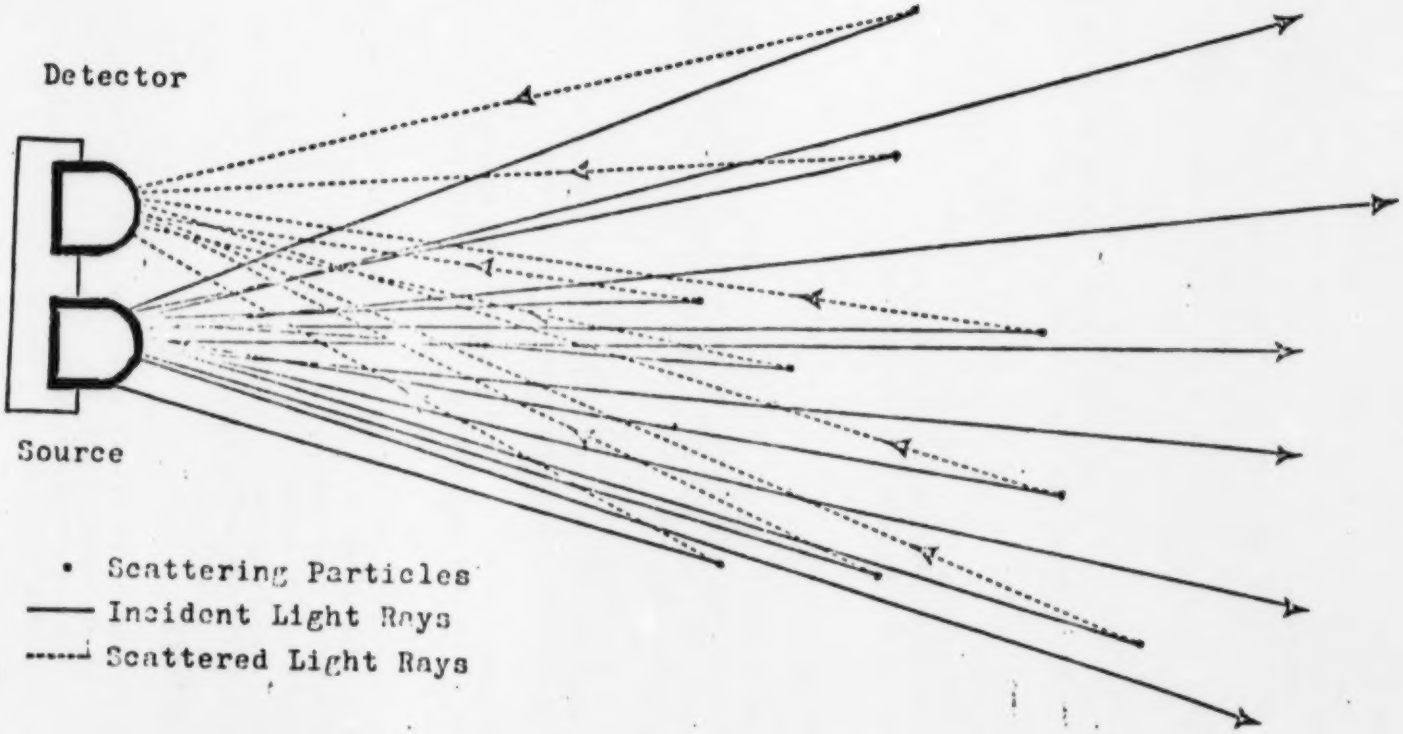
Detector
Source
• Scattering Particles
Incident Light Rays
Scattered Light Rays

Figure VIII-4. Backscatter Device (From George and Zeller (1973))

such a relationship was empirically valid to an accuracy of 20% under varying conditions where the visual range varied between .1 km and 60 km. Barteneva (1960) made numerous measurements under a wide range of environmental conditions and concluded that over the visual range of 10 km to 200 km a relation similar to that above was found to exist but with an exponent of 1.44 rather than 1.5. Twomey and Howell (1965) found a similar relationship existed with an exponent of 1. Thus, it appears that backscatter measurements at one location may define a peculiar constant, C, and exponent.

Experiments in Germany (Vogt, 1968) have shown that the performance of backscatter devices for measuring visibility ($<$20 km, in this instance) matched that of experienced observers.

Twomey and Howell (1965) cited that the use of white light, as opposed to monochromatic light, produced a better correlation between visual range and backscattering. Although white light will eliminate some uncertainty in this relationship, the natural processes affecting aerosol size introduce a considerable non-uniqueness in the L_v-S relationship.

8.3.5. Visibility Observations

Procedures for human observers making visibility observations are outlined in the Federal Meteorological Handbook No. 1 (1970): Surface Observations (Chapter A6), and should be consulted when human observations of visibility are required.

Airports are a source of background visibility data which often is in the form of prevailing visibility, as defined in the above Handbook. The Handbook indicates that prevailing visibility is the:

> "greatest horizontal visibility prevailing throughout at least half of the horizon circle which need not necessarily be continuous."

Consequently, the prevailing visibility is not necessarily the maximum observed visibility. Furthermore, a large number of stations recording visibility data primarily for aircraft operations indicate visibilities in excess of 15 miles as 15+ miles. Thus, this is a shortcoming of existing background visibility data and caution must be used in the compilation of data summaries and trends.

8.4. CONCLUDING REMARKS

Additional experimental verification of the above methodologies is needed in the rural environment with its very large visibilities. This will facilitate the determination of the most satisfactory method of quantitatively assessing visibility in the Northern Great Plains.

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SECTION IX

TRACE ELEMENTS

9.1 INTRODUCTION

It is desirable to know the type, magnitude, and effects of trace elements emitted during the combustion of fossil fuels. There is particular interest to determine the above factors for the combustion of coal in the NGP, because of the anticipated magnitude of the projected development. An accurate assessment of the chain of events leading from the concentration of a particular trace element in the coal to the deposition in a sink of some type has never been made. In fact, only limited knowledge exists regarding each single event. In order to make this accurate assessment, one must identify: 1) the concentration and form of trace elements in the coal; 2) the fate of these trace elements during the combustion process; 3) the resultant concentrations of trace elements in the atmosphere, lithosphere, and hydrosphere; and finally, 4) the potential deleterious effects resulting from these concentrations.

This section of the work group report will attempt to discuss the four aforementioned aspects, which must be considered when discussing the potential effects of trace element emissions from fuel conversion facilities. A program is under way by this work group to provide data in each of the four areas. This program is discussed in detail in section 9.3.

9.2 TRACE ELEMENT CONCENTRATIONS IN COAL

The U.S. Geological Survey is the most active organization in collecting and analyzing coal samples for trace element content. The Atomic Energy Commission, the Office of Coal Research, some state geological surveys, and some universities have performed spot sample analyses on a few trace elements. Also, the coal companies and utilities industries are performing periodic analyses. Some of this data are contained in environmental analyses and environmental impact statements submitted by the subject companies and are presented in the appendix to this report.

Figures IX-1 and IX-2 in appendix IX-A show the location of the samples obtained for U.S.G.S. analyses in coal found in the NGP. Table IX-1 presents the average expected concentrations of certain trace elements. The appendix to this section provides data identifying the concentration of certain trace elements in coal as collected by various organizations. The organization performing the analyses (or having it done) is indicated in the table heading. All trace element concentrations are listed in ppm (weight) unless otherwise noted. Care should be exhibited in making substantive comparisons among the data. Analytical techniques, core sample vs. operating

Table IX-1

Average Trace Element Concentrations in Western Coal

U.S.G.S.

B	150. ppm	Ni	7.ppm
Ba	500.	Pb	5.
Be	0.5	Sc	1.
Co	2.	Sn	1.
Cr	5.	Sr	200.
Cu	20.	Ti	250.
Ga	2.	V	10.
Ge	1.	Y	7.
La	6.	Yb	.5
Mn	100.	Zn	10.
Mo	1.5	Zr	15.

mine sample, type of drill pipe, type of drilling fluid, and location of sample in the bed (i.e., top or bottom) are all factors which may explain variations in the data. All of these same considerations must be taken into account when one attempts to generate average trace element concentrations for the purpose of estimating subsequent emissions.

For the sake of comparing NGP coal trace element concentrations with that of other U.S. coal, Figure IX-1 is presented. Again, it must be cautioned that these average data are subject to many variations. Also, the data presented are based upon a limited number of observations.

Discussion of the "major" trace quantities in coal should include sulfur and ash content of coal. The U.S.G.S. has included analyses of many NGP coals in the workgroup B report. Those analyses are included in the report as Table IX-18 in appendix IX-A for reference. It is noted that the sulfur content ranges from 0.2% to 2.5% (with most below 1.0%) on an "as received" basis, and ash content ranges from 3.2% to 14.4% (with most below 8%) (A.R.)

Some analyses have been performed on collected fly ash and bottom ash for trace element concentrations. Since these data are necessarily a function of the coal burned, no discussion is included in this report.

9.3 FATE OF TRACE ELEMENTS DURING COMBUSTION

To our knowledge, only one published study exists which considered a total trace element mass balance approach. Work performed by the Oak Ridge National Laboratory, funded by the National Science Foundation on the TVA Allen steam plant at Memphis, Tennessee, was published in March 1973. A mass balance for 18 trace elements was performed, using operating data and samples collected between January 24 and February 4, 1972. The plant operated at a load of 240 megawatts during this period and was fired with coal. Table IX-2 presents trace element particulate mass emission rates of the 18 elements, based upon a firing rate of 82.7 tons of coal per hour. It must be remembered that a portion of some of these trace elements may have been volatilized during combustion; hence, not showing up in the particulate form. This would indicate that the figures shown in columns 2 and 3 of Table IX-2 would be unrealistically low. For more details regarding the emissions, sampling approach, and analytical methodologies, please refer to the report (6).

Because of the limited knowledge concerning the fate of trace elements during combustion, we have entered into a contract for the performance of an extensive sampling program. Samples of coal, bottom ash, collected fly ash, and stack gas will be collected. Figure IX-3 in the appendix depicts a typical coal fired generating plant and illustrates the four sampling points. Three coal fired power plants will be sampled. Two of the plants burn sub-bituminous coal and the other burns lignite.

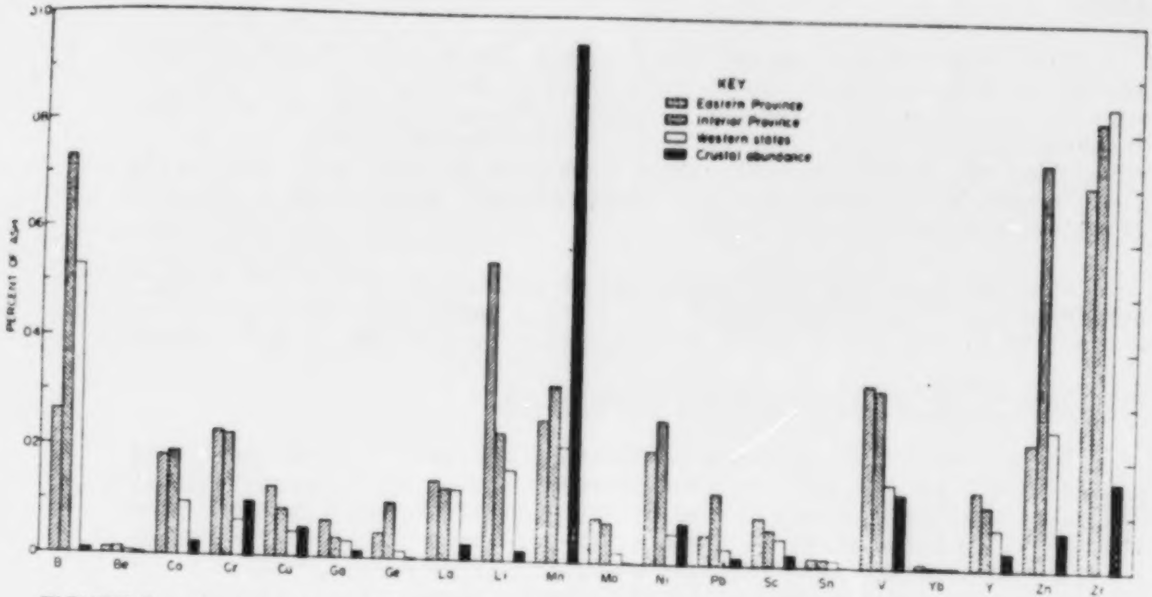

FIGURE 2. - Average Trace Element Content in Ash of Coal From Three Areas Compared With Crustal Abundance (4).

Figure IX-1

Average Trace Element Content in Ash
of Coal From Three Areas
Compared With Crustal Abundance (4).

ESSO Research and Engineering

Table IX-2

TVA Trace Element Particulate Emissions

Coal Input = 82.7 ton/hour
Unit Load = 240 MW

		Trace element in coal gram/min	Trace element stack gas gram/min	% of Trace element emitted
Aluminum	(1)	13,000	68	0.5
Antimony	(1)	0.75	--	--
Arsenic	(2)	6.2	0.039	0.6
Beryllium	(2)	6.3	0.019	0.3
Calcium	(1)	4,700	9.5	0.2
Cadmium	(2)	0.63	0.014	2.2
Copper	(2)	63	0.8	1.3
Iron	(1)	16,000	460	2.9
Lead	(2)	25	0.2	0.8
Magnesium	(1)	2,100	17	0.8
Manganese	(1)	67	1	1.5
Nickel	(2)	130	1.9	1.5
Pottasium	(1)	2,700	25	0.9
Selenium	(1)	4.0	1.5	37.5
Sodium	(1)	860	5.5	0.6
Titanium	(1)	890	5	0.6
Vanadium	(1)	26	0.12	0.5
Zinc	(2)	110	1.7	1.6

(1) Neutron Activation Analyses

(2) Spark source mass spectrometry analyses

Analyses of the collected samples will occur in two phases. The first phase will consist of a semi-quantitative assessment of the samples, using a spark source mass spectrometry technique. Concentrations for the 53 elements listed in Table IX-19 of Appendix IX-A will be determined. The second phase will employ the use of highly accurate quantitative techniques in order to identify concentrations for the 27 elements listed in Table IX-20 of Appendix IX-A. The techniques will include atomic absorption spectrometry, selective ion electrode, visible spectrophotometry, and fluorometry. Through this detailed analyses we will be able to define what happens to a particular trace element as it is subjected to coal combustion and subsequent gas cooling and collection. It is speculated that most trace elements remain as particulate matter and, hence, are collected in the particulate collection device. However, it is also suggested that some of the trace elements are highly volatile and undergo sublimation. These elements which seem to exhibit this volatility include mercury, arsenic, selenium, cadmium, lead, and fluorine. It has been reported that as much as 90 percent of the mercury in the coal escapes in the gaseous form.

Another aspect of trace element emissions which must be considered is the concentration of the element in various particle size ranges. There is some evidence (15) which suggests that cadmium, chromium, manganese, selenium, arsenic, nickel, zinc, antimony, and lead tend to be more highly concentrated in the sub-micron particle range. This aspect has broad health-related connotations, since the sub-micron particles are in the respirable range and subsequently taken into the blood stream. Resolution of this facet is beyond the scope of work of the present sampling effort. It is, however, in the plans for the FY-75 activities of this work group. The EPA NERC-RTP has a program under way at the present time on an Eastern coal-fired plant which will provide particle size analyses.

One theory which has come forth to explain this particle size function phenomena is that the trace element volatilizes during combustion and later, after the gases are cooled in the waste heat recovery equipment, the element condenses on the small sub-micron particles in the flue gases. Two justifications are put forth for the basis of this theory. First, all of the elements mentioned, with the exception of nickel and chromium, have boiling points below the normal 2400 to 2900° F combustion zone temperature. Second, small particles provide a large surface area to mass ratio, which is an important aspect of the chemistry of adsorption.

In summary, the understanding of the chemistry of trace element volatilization is critical to the design of proper air pollution control equipment. Because of the aforementioned volatility and subsequent condensation premise, there may exist a significant control advantage in favor of a wet scrubber over a hot side electrostatic precipitator. These control techniques are discussed in detail in Section VII of this report.

The EPA is presently studying the type and magnitude of trace elements that may be expected from the coal gasification process. (4) All efforts to date have been on a bench scale basis. Programs are designed to study the same parameters on a pilot plant basis in FY-75. The three pilot plant candidates are those in Chicago, Illinois; Rapid City, South Dakota; and Bruceton, Pennsylvania. Table IX-3 lists the potential losses of trace element to the atmosphere in the coal gasification process based upon the work to date. It must be emphasized that these data are very preliminary in nature. Any extrapolations to a broad scale may well misrepresent the facts on either a low or high side. EPA Headquarters (NERC - RTP - CSL) have active programs which will produce data in this area. As those data become available, it will be published in conjunction with the NGP work, either as special reports or as a part of the Atmospheric Aspects Work Group final report in 1975.

There may be some justification for thinking that the reducing atmosphere in which the coal gasification takes place may cause slightly lower potential trace element emissions compared to the oxidizing atmosphere of the power plant. The work planned in FY-75 should shed light on this subject.

There is undoubtedly interest in what magnitude of emissions may be expected from fuel conversion facilities. Estimates and projections will be made, based upon the data contained in the NGP report. Therefore, for the sake of information, trace element emissions for power plants and coal gasification plants were calculated. Plant sizes, particulate control efficiency, and fuel input were assumed to be the same as presented in Tables III-9 and III-10 of this report. Table IX-23 (Appendix IX-A) is included in the report to show the potential coal gasification trace element emissions based upon Eastern coal.

The preliminary nature of the estimations presented in these Tables cannot be over-emphasized. These are based on a limited amount of data. Actual emissions may vary by an order of magnitude or more. This points out the significance of the successful performance of future trace element source sampling programs.

9.4 TRACE ELEMENT AIR QUALITY CONCENTRATIONS

A complete discussion of the past and future attempts to monitor trace element air quality concentrations is presented in Sections II and X of this report. There will be some attempts in the future made to predict air quality concentrations through the use of a diffusion model. An air quality monitoring program is proposed to be operated in conjunction with an expanded trace element source sampling program in FY-75 (see Section X).

9.5 TRACE ELEMENT EFFECTS

Probably the most difficult aspect of the entire study of trace elements is the determination of the levels at which each element is

Table IX-3

Trace Element Volatilization During the Gasification Process

	% of Element vaporized at 1020° F (4)
Mercury	96
Selenium	74
Arsenic	65
Tellurium	64
Lead	63
Cadmium	62
Antimony	33
Vanadium	30
Nickel	24
Beryllium	18
Chromium	0

(4) Fate of Trace Constituents of Coal During Gasification; EPA 650/2-73-004; August 1973

toxic. This determination, in most cases, requires years of research work. Effects which must be considered include physiological, medical, vegetative, and materials. The EPA has promulgated emission standards for asbestos, beryllium, and mercury from some stationary sources. These standards do not apply, however, to fuel conversion facilities. The emission limitation for mercury is 2300 grams per 24 hour period, and the limit for beryllium is 10 grams per 24 hour period. Sources have the option on the beryllium standard of complying with a 0.01 ug/m^3 thirty day average. These standards were promulgated (7) under the authority of Section 112 of the 1970 Clean Air Act, as amended. Technical support documents are available upon request.

It was reported in the support documents that effects of airborne beryllium on human health include both acute and chronic lethal inhalation effects, as well as skin and conjunctival effects. Insufficient data exists to suspect beryllium as a human carcinogen, but the lack of any mechanism for the total elimination of beryllium body burdens and the subsequent long residence time may enhance the opportunity for cancer induction. The exposure to metallic mercury vapors may cause central nervous system injury and renal damage. It was noted that a total body burden must be considered; i.e., that mercury taken in through food, water and breathing. It was also noted that the form of mercury is extremely important when discussing toxicity. Methyl mercury is considered to be by far the most hazardous mercury compound, followed next by elemental mercury vapors. It was suggested that mercuric oxide is not nearly as toxic as elemental mercury.

EPA is charged with the responsibility in Section 112 of the Act to define a hazardous air pollutant and subsequently propose and promulgate an emission standard, if the Administrator determines that the pollutant "may cause or contribute to an increase in mortality or an increase in serious, irreversible, or incapacitating reversible illness."

There is some evidence to suggest that certain trace elements are concentrated in the smallest respirable particles emitted from the combustion process. (15) This premise has considerable environmental health significance, because these small particles are most effectively passed into the blood stream. Particles with equivalent aerodynamic diameters of less than one micron deposit predominantly in the alveolar regions of the lung when inhaled. In those regions, the absorption efficiency for most of the trace elements is 50 to 80 percent. Larger particles, on the other hand, are trapped in the nasal, pharyngeal and bronchial regions of the respiratory system. They are subsequently removed by the wave-like motion of the cilia and are then deposited in the stomach, where the adsorption efficiency is only 5 to 15 percent.

In conclusion, the source sampling program being conducted with FY-74 funds is the first step in the determination of the effects of trace elements. The proposed FY-75 program will provide the second step in the trace element study; i.e., the correlation of trace element emissions with atmospheric concentrations. These two steps are significant research items. The final research step is necessarily a long-term, on-going program. The possible health and vegetation hazards, the potential contribution to materials corrosion, the action of some trace elements as a catalyst for the formation of secondary pollutants, and the geophysical and meteorological effects of particulate trace element concentrations serve as key incentives to perform meaningful research in the trace element area.

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Appendix IX-A

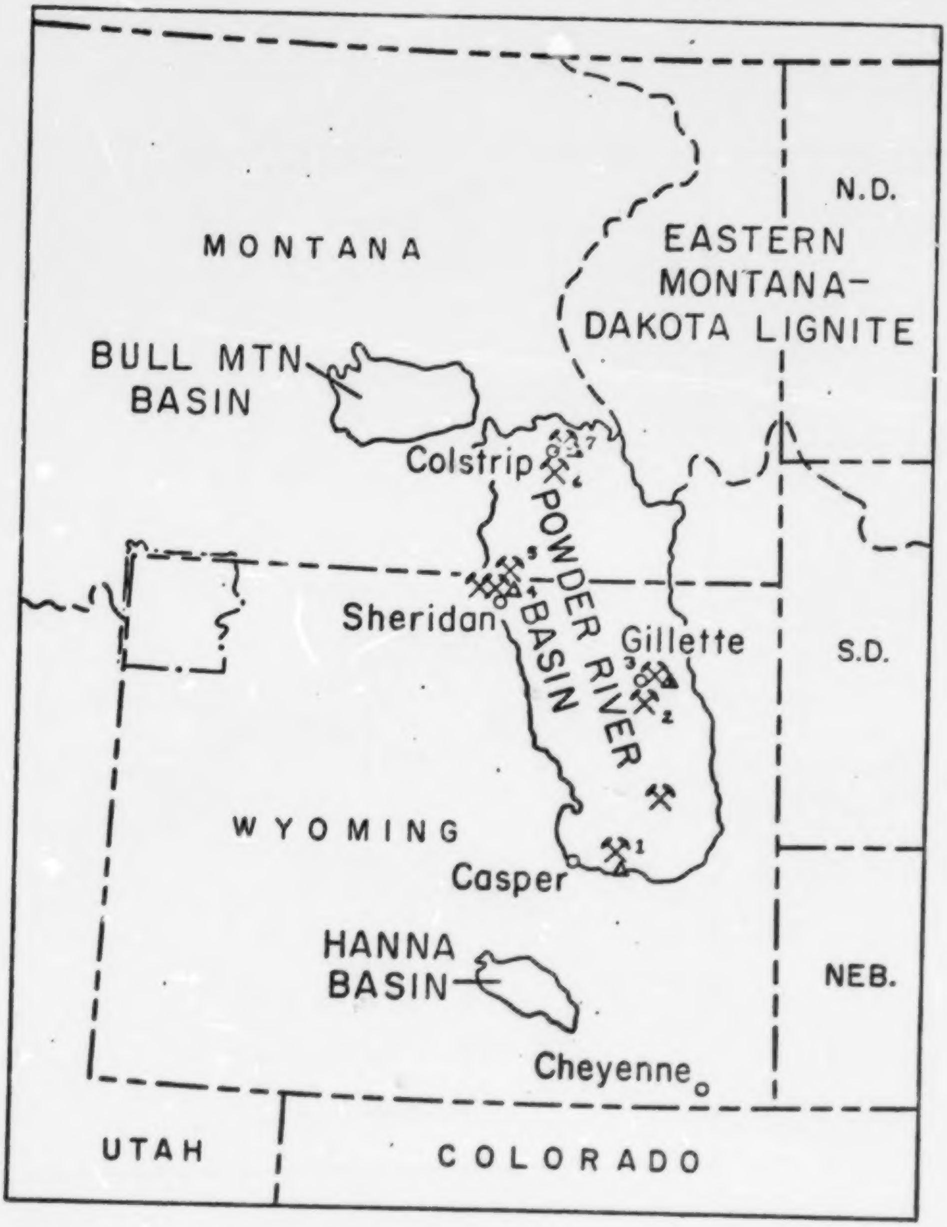

MONTANA
N.D.
EASTERN MONTANA-DAKOTA LIGNITE
BULL MTN BASIN
Colstrip
POWDER RIVER BASIN
Sheridan
Gillette
S.D.
WYOMING
Casper
HANNA BASIN
NEB.
Cheyenne
UTAH
COLORADO
1
2
3
4
5
6
7

Figure 1.--Location of coal mines in the Powder River Basin from which samples collected and analyzed. 1, Dave Johnston; 2, Belle Ayr (Amax); 3, Wyodak; 4, Big Horn; 5, Decker; 6, Big Sky; 7, Rosebud. Solid triangles indicate coal-fueled power plants.

Figure IX-1

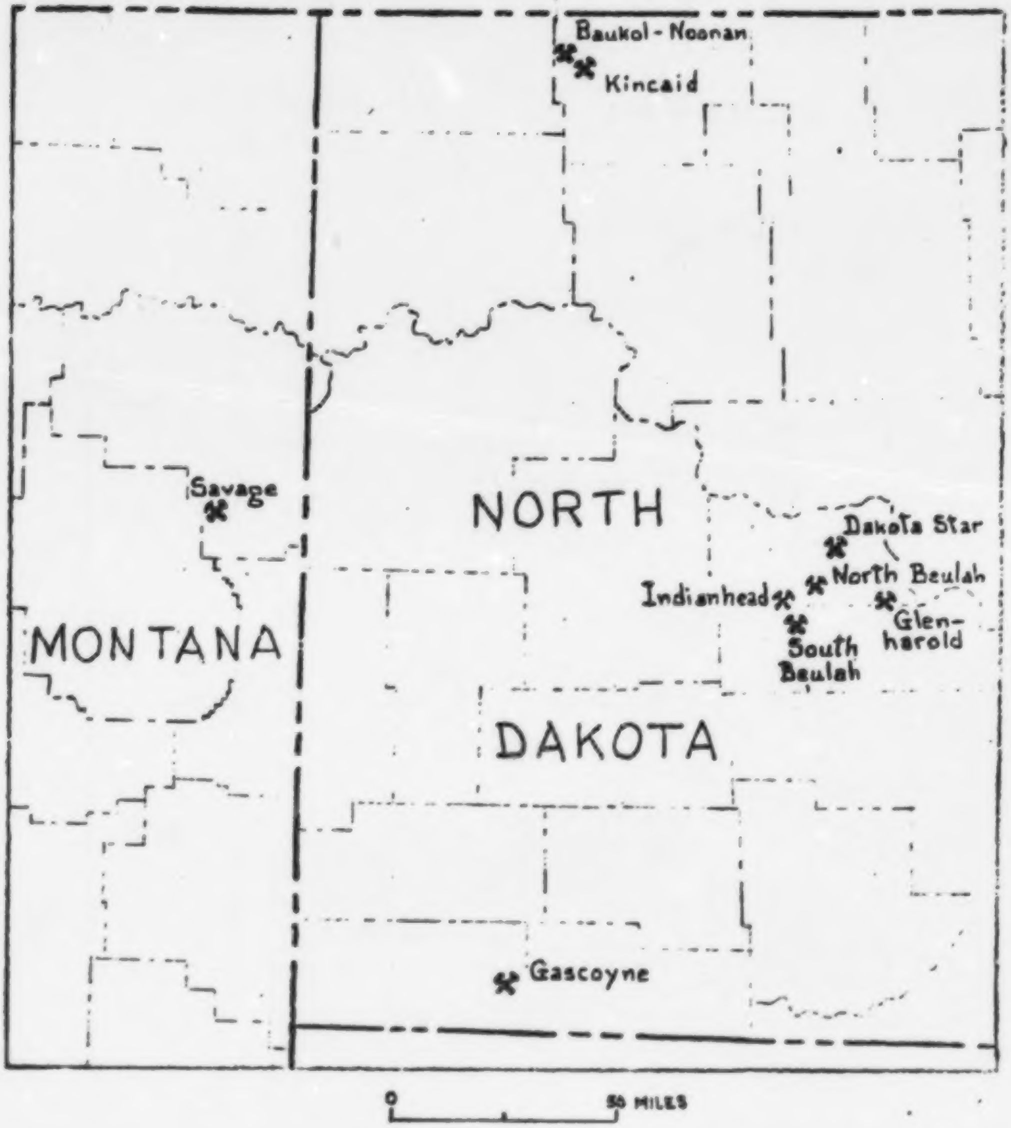

Baukol-Noonan
Kincaid
Savage
NORTH
DAKOTA
MONTANA
Dakota Star
North Beulah
Indianhead
Glen-harold
South Beulah
Gascoyne
0
50 MILES

Figure 2.--Location of lignite mines in western North Dakota and eastern Montana for which chemical analyses are reported.

Figure IX-2

Table IX-1

Table 1.--Quantitative determinations (in ppm) for [illegible] trace elements in [illegible] samples of coal from the Powder River Basin of northeastern Wyoming and southeastern Montana. [In thickness column, (T) and (B) indicate top and bottom of bed, respectively. Values for Cd, Cu, Li, Pb, and Zn are calculated from analyses on ash of coal.]

Sample No.	Thickness of sample interval (ft)	As	Cd	Cu	F	Hg	Li	Pb	Sb	Se	Th	U	Zn	Ash (percent)
BADGER COAL BED, DAVE JOHNSTON MINE, GLENROCK, WYOMING														
D161315	5.(T)	4	<0.1	15.8	---	0.140	10.7	10.0	---	2.3	5.0	2.4	12.6	15.8
D161316	5.5	3	.1	16.9	70	.128	11.6	8.4	0.6	1.6	6.6	2.2	4.0	12.5
SCHOOL COAL BED, DAVE JOHNSTON MINE, GLENROCK, WYOMING														
D161314	6.(T)	2	<0.1	6.2	---	0.088	1.5	5.1	---	0.9	<1.5	0.3	2.6	8.20
D161313	5.	1	<.1	5.7	---	.070	1.0	5.1	---	.7	<1.5	.4	3.4	7.36
D161312	5.	6	.15	18.5	50	.350	4.1	5.9	0.2	3.5	<1.5	<.3	4.1	8.62
D161311	5.	2	<.1	19.0	---	.095	5.8	6.1	---	.6	<1.5	.8	4.5	9.76
D161310	5.(B)	1	<.1	13.6	---	.059	3.5	7.1	---	.8	<1.5	1.1	2.9	10.3
WYODAK-ANDERSON COAL BED, BELLE AYR (AMAX) MINE, GILLETTE, WYOMING														
D160988	(Tipple)	2	0.1	13.3	30	0.13	1.9	5.5	0.2	1.8	<1.5	0.6	6.8	6.64
D163516	2.1(T)	4	.1	12.0	90	.28	1.2	2.2	.4	2.2	<1.5	2.9	6.8	8.69
D163517	4.2	3	.2	45.	80	.13	4.4	5.3	.7	2.0	7.7	1.7	5.9	11.7
D163518	5.	2	.1	8.6	40	.13	2.0	<1.5	.3	.6	4.8	.4	7.6	7.06
D163519	5.	2	<.1	10.7	90	.10	1.2	1.9	.2	.3	<1.5	.4	4.6	6.42
D163520	5.	2	<.1	4.2	65	.08	<.5	<1.5	.2	.4	<1.5	<.3	2.7	4.83
D163521	5.	2	<.1	5.3	60	.06	.5	1.5	.1	.5	<1.5	.6	2.1	4.38
D163522	(Tipple)	2	<.1	12.3	50	.09	1.4	2.2	.2	.9	<1.5	.9	4.4	6.32
WYODAK-ANDERSON COAL BED, WYODAK MINE, GILLETTE, WYOMING														
D160987	(Tipple)	1	<0.1	7.7	30	0.081	1.6	5.6	0.1	0.6	<1.5	0.6	4.2	6.42
D160986	(Shot-pile)	2	.15	22.0	40	.108	4.1	5.7	.3	1.4	<1.5	1.5	12.5	8.82
D160985	3.(T)	2	<.1	3.3	30	.055	.7	3.9	<.1	.4	<1.5	<.2	5.5	4.90
D160984	10.	3	.16	10.0	40	.214	2.2	5.7	.2	1.4	<1.5	.6	7.1	7.54
D160983	10.	2	<.1	20.4	50	.176	4.0	7.1	.3	.8	3.1	.9	15.4	10.6
D160982	10.	1	<.1	8.3	40	.068	2.0	5.7	.1	.6	<1.5	.6	5.6	6.80
D160981	.5	2	<.1	51.	200	.150	69.	440.	.5	.6	7.9	3.2	25.	84.9
D160980	3.5	1	<.1	9.8	50	.106	4.2	8.1	.3	1.0	<1.5	.5	7.5	9.78
D160979	5.	1	<.1	12.4	40	.068	3.6	8.2	.3	.9	<1.5	.9	8.0	10.0
D160978	5.	1	<.1	7.6	40	.064	1.1	6.2	.3	.4	<1.5	.5	3.3	6.78
D160977	5.	<1	<.1	5.6	30	.063	1.3	7.2	.2	.3	<1.5	.5	4.4	7.34
D160976	5.	<1	<.1	3.8	30	.050	1.9	6.0	.1	1.9	<1.5	.5	3.5	6.20
MONARCH COAL BED, BIG HORN MINE, SHERIDAN, WYOMING														
D161320	(Tipple)	3	0.05	6.4	60	0.090	1.8	2.6	0.2	0.3	<1.5	0.4	9.0	4.74
ANDERSON-DIETZ COAL BED, DECKER MINE, DECKER, MONTANA														
D161317	(Tipple)	3	<0.05	8.6	---	0.103	4.4	2.3	---	0.4	<1.5	0.6	3.8	4.76
D161318	do.	4	<.05	8.2	50	.108	4.4	2.4	0.3	.6	<1.5	.6	4.5	4.89
D161319	do.	3	<.05	9.2	---	.110	5.3	2.6	---	.9	<1.5	.8	5.8	5.36
ROSEBUD COAL BED, BIG SKY MINE, COLSTRIP, MONTANA														
D163179	6.8(T)	1	<0.1	7.6	105	0.04	12.	6.0	0.3	0.7	<1.5	0.4	1.9	9.17
D163180	5.7	1	<.1	6.2	<20	.03	18.	5.9	.3	.2	<1.5	.6	2.4	9.84
D163181	5.0	1	<.1	6.5	<20	.06	13.	5.0	.2	.2	<1.5	.4	2.6	8.28
D163182	5.0	1	<.1	8.7	40	.08	10.	5.6	.3	.8	<1.5	.5	3.0	10.2
D163183	2.1	1	<.1	3.6	<20	.06	3.7	3.0	.4	.8	<1.5	.5	2.0	5.01
D163192	.5	2	<.1	43.	100	.05	122.	36.	.5	2.4	<1.5	1.5	23.	51.7
D163184	2.5(B)	2	<.1	7.0	20	.14	8.9	6.4	.5	.8	<1.5	.8	3.1	9.11
D163187	(Tipple)	2	.1	7.7	60	.07	14.	7.5	.5	.5	<1.5	.7	5.4	11.5
McKAY COAL BED, BIG SKY MINE, COLSTRIP, MONTANA														
D163186	5.4(T)	1	<0.1	4.6	70	0.05	6.6	5.4	2.7	0.4	<1.5	0.8	2.5	7.18
ROSEBUD COAL BED, ROSEBUD MINE, COLSTRIP, MONTANA														
D161321	(Shot-pile)	2	<0.1	10.1	60	0.075	14.	7.9	0.7	0.9	5.1	1.2	2.1	13.0
D161322	do.	2	<.1	10.7	---	.053	24.	8.8	---	1.0	4.0	1.3	2.5	13.7
McKAY COAL BED (CORES), ROSEBUD MINE, COLSTRIP, MONTANA														
D161796	?	---	---	---	---	0.144	---	---	---	---	---	---	---	9.73
D161797	?	---	---	---	---	.160	---	---	---	---	---	---	---	9.60
D161798	?	---	---	---	---	.143	---	---	---	---	---	---	---	10.0
D161799	?	---	---	---	---	.148	---	---	---	---	---	---	---	13.1

Table IX-2

Table 2.—Semiquantitative spectrographic analyses (in ppm) for 19 trace elements in 67 samples of coal from the Powder River Basin of northeastern Wyoming and southeastern Montana. [In the sample interval column, (T) and (B) indicate top and bottom, respectively. All values have been calculated from analyses on ash of coal.]

Sample No.	Sample interval (ft)	B	Ba	Be	Co	Cr	Cu	La	Mn	Mo	Nb	Ni	Sc	Sn	Sr	Ti	V	Y	Yb	Zr
BADGER COAL BED, DAVE JOHNSTON MINE, GLENROCK, WYO.																				
D161315	5.(T)	100	50	0.5	2.	15	7	10	100	2.	3.	5.	5.	<0.5	70	500	50	5	0.5	70
D161316	5.5	100	100	.5	1.	10	7	10	200	2.	2.	7.	2.	< .5	150	500	20	5	.5	10
SCHOOL COAL BED, DAVE JOHNSTON MINE, GLENROCK, WYO.																				
D161314	6.(T)	50	50	0.15	1.	5	1	5	100	0.5	<1.5	3.	1.	<0.5	150	300	10	3	0.15	10
D161313	5.	30	70	< .15	1.	5	1	<5	150	< .5	<1.5	1.5	1.	< .5	150	200	10	2	.2	7
D161312	5.	70	150	.15	1.5	7	3	<5	150	.5	<1.5	7.	1.5	< .5	150	700	15	3	.3	15
D161311	5.	50	200	.3	1.5	7	3	7	70	1.	2.	3.	3.	< .5	300	700	15	3	.3	20
D161310	5.(B)	70	150	.3	1.5	15	7	7	70	1.	3.	3.	3.	< .5	150	700	30	5	.3	15
WYODAK-ANDERSON COAL BED, BELLE AYR (AMAX) MINE, GILLETTE, WYO.																				
D160988	(Tipple)	20	200	0.2	2.	5	2	10	20	0.5	1.5	5.	2.	<0.5	30	300	15	3	0.3	10
D163516	2.1(T)	30	300	.7	3.	7	3	15	200	1.5	2.	10.	5.	< .5	200	300	30	7	.7	15
D163517	4.2	20	300	.7	2.	10	3	20	30	1.	2.	3.	7.	< .5	200	700	30	5	.5	20
D163518	5.	30	200	.3	1.5	5	2	10	20	.5	<1.5	3.	2.	< .5	70	300	10	5	.5	15
D163519	5.	30	200	.2	1.	5	1	5	30	.5	1.5	3.	2.	< .5	70	200	10	2	.3	20
D163520	5.	30	200	<.15	1.	1.5	1	<5	30	.3	<1.5	3.	1.5	< .5	70	150	7	2	.2	7
D163521	5.	30	200	<.15	1.5	3	1	<5	20	.7	<1.5	3.	1.5	< .5	70	150	7	1.5	.15	10
D163522	(Tipple)	20	200	.2	1.	5	1.5	<5	20	.7	1.5	3.	3.	<.5	70	200	10	2	.3	10
WYODAK-ANDERSON COAL BED, WYODAK MINE, GILLETTE, WYO.																				
D160987	(Tipple)	30	200	<0.15	1.	5	2	<5	10	0.5	1.	2.	1.	<0.5	50	200	10	2	0.2	10
D160986	(Shot-pile)	50	200	.3	3.	7	3	<5	200	1.	2.	7.	3.	< .5	50	500	30	5	.7	20
D160985	3.(T)	30	150	< .15	1.5	2	2	<5	50	.3	<1.	3.	.7	< .5	20	100	7	2	.2	5
D160984	10.	50	150	.2	2.	5	2	7	50	.5	1.5	5.	1.	< .5	20	200	15	1	.1	10
D160983	10.	30	200	.3	2.	7	3	10	30	.7	2.	7.	2.	< .5	30	500	20	5	.5	15
D160982	10.	30	200	< .15	1.	5	2	<5	20	.5	<1.	5.	1.	< .5	30	700	10	2	.2	10
D160981	.5	50	500	< .15	< .5	50	20	<5	50	< .5	20.	15.	15.	< .5	150	5,000	150	<1	2.	150
D160980	3.5	20	300	< .15	2.	7	3	<5	15	.7	<1.	3.	1.5	< .5	50	300	15	2	.3	15
D160979	5.	20	300	< .15	1.5	10	3	<5	15	.7	<1.	3.	1.5	< .5	30	300	20	3	.3	15
D160978	5.	20	300	< .15	.7	2	1.5	<5	10	.5	<1.	2.	1.	< .5	50	200	7	2	.2	10
D160977	5.	20	300	< .15	.7	2	2	<5	20	.5	2.	2.	.7	< .5	50	200	5	1.5	.2	10
D160976	5.	30	300	< .15	1.	2	2	<5	10	.7	3.	2.	1.	< .5	70	200	5	2	.2	10
MONARCH COAL BED, BIG HORN MINE, SHERIDAN, WYO.																				
D161320	(Tipple)	30	500	0.15	1.5	3	1.5	3	30	0.5	<1.	5.	1.5	<0.5	100	200	10	3	0.15	10
"ANDERSON-DIETZ" COAL BED, DECKER MINE, DECKER, MONT.																				
D161317	(Tipple)	30	500	0.15	0.7	3	1.5	3	7	1.5	1.	3.	1.5	<0.5	300	300	10	3	0.15	10
D161318	do.	30	500	.15	1.	3	1.5	3	15	1.5	<1.	3.	1.5	< .5	300	300	15	3	.15	10
D161319	do.	30	500	.15	1.	3	1.5	3	10	1.5	<1.	3.	1.5	< .5	300	300	10	3	.15	10
ROSEBUD COAL BED, BIG SKY MINE, COLSTRIP, MONT.																				
D163179	6.8(T)	70	700	0.7	<0.5	5	3	7	50	10.	<1.	1.5	1.5	<0.5	300	300	7	3	0.3	30
D163180	5.7	70	150	< .15	< .5	5	3	7	70	2.	2.	1.5	1.5	< .5	200	300	7	3	.3	20
D163181	5.0	50	150	< .15	< .5	5	2	5	20	1.5	<1.	1.	1.	< .5	70	200	5	2	.2	15
D163182	5.0	50	150	< .15	< .5	3	3	<5	30	3.	<1.	1.	1.5	< .5	100	300	7	3	.3	20
D163183	2.1	70	100	.15	.5	1.5	3	5	50	5.	<1.	1.5	1.	< .5	70	150	5	3	.15	10
D163192	.5	30	70	< .15	< .5	15	15	<5	70	5.	<1.	<3.	<3.	< .5	70	3,000	30	10	1.	150
D163184	2.5(B)	70	100	.7	< .5	2	5	7	70	3.	5.	1.5	2.	< .5	100	300	7	5	.3	20
D163187	(Tipple)	50	500	.5	1.	3	3	<5	30	7.	1.5	3.	1.5	< .5	150	300	7	2	.3	20
McKAY COAL BED, BIG SKY MINE, COLSTRIP, MONT.																				
D163186	5.4(T)	70	200	1.	<0.5	2	2	5	15	0.7	1.	2.	1.	<0.5	200	150	5	3	0.3	10
ROSEBUD COAL BED, ROSEBUD MINE, COLSTRIP, MONT.																				
D161321	(Shot-pile)	100	200	0.3	<1.	3	7	<5	100	3.	3.	0.7	1.5	<0.5	200	300	10	3	0.3	30
D161322	do.	100	200	.5	<1.	5	5	<5	100	2.	5.	1.	2.	< .5	300	1,000	10	5	.5	50
McKAY COAL BED (CORES), ROSEBUD MINE, COLSTRIP, MONT.																				
D161796	?	150	30	1.5	2.	2	3	<5	30	5.	2.	5.	1.5	<0.5	200	200	7	5	<0.1	15
D161797	?	150	200	1.5	1.5	3	3	<5	50	1.5	3.	5.	1.5	< .5	200	300	7	5	.5	20
D161798	?	100	700	.7	<1.	3	3	<5	20	1.5	2.	1.	<1.	< .5	300	150	5	3	.3	10
D161799	?	70	50	1.5	<1.	3	3	<5	20	2.	<1.5	1.5	<1.	< .5	200	300	10	3	.3	20

Table IX-3

Core Samples

Sample No.	Thickness of sample interval feet	As	Cd	Cu	F	Hg	Li	Pb	Sb	Se	Th	U	Zn	Ash
UNIDENTIFIED COAL BEDS IN 12 CORES, NORTHEASTERN WYOMING AND SOUTHEASTERN MONTANA														
D160662	9(T)	2	---	10.7	80	0.035	0.9	---	<3.3	<0.1	<1.5	<0.2	5.9	3.20
D160663	3(B)	2	0.1	26.	70	.082	8.8	18.7	13.7	.4	<1.5	.8	12.2	6.80
D160666	7	2	<.1	13.6	40	.037	1.6	17.7	4.7	<.1	<1.5	.2	3.7	3.25
D160667	1	3	<.1	27.	40	.051	4.2	75.	19.1	<.1	<1.5	.4	8.9	4.56
D160668	11(T)	1	<.1	11.2	70	.044	1.4	13.7	3.8	.2	<1.5	<.2	3.8	4.56
D160669	10	1	<.1	6.2	60	.030	1.0	6.7	1.9	<.1	<1.5	<.2	3.2	3.43
D160670	3(B)	3	.1	10.3	70	.106	3.1	8.5	1.8	.6	<1.5	1.2	17.1	7.12
D160671	4	2	<.1	6.9	70	.035	3.5	6.9	3.0	<.1	<1.5	.9	12.8	6.92
D160672	8(T)	2	.15	10.6	100	.049	3.5	8.6	1.6	.5	<1.5	.8	28.	8.16
D160673	10(B)	2	<.1	5.8	50	.099	1.3	3.9	1.3	.2	<1.5	<.2	5.6	4.87
D161073	10(T)	3	<.1	11.3	---	.043	2.7	11.3	1.3	.6	<1.5	.9	5.8	8.08
D161074	10(B)	4	.1	16.4	---	.063	2.5	30.	1.5	.5	<1.5	.3	7.3	7.30
D161075	1	3	.1	20.	---	.039	1.0	14.1	2.6	.9	<1.5	.3	10.3	6.42
D161076	8(T)	3	<.1	6.6	---	.035	1.6	9.1	1.6	.5	<1.5	.4	2.0	8.24
D161077	10(B)	2	<.1	4.9	---	.021	.8	7.0	.7	.3	<1.5	<.2	1.7	5.40
D161078	7	3	<.1	11.2	---	.058	1.3	7.4	.9	1.0	<1.5	<.2	2.6	6.20
D161079	9(T)	3	.15	20.	---	.181	6.4	9.8	1.4	1.5	5.6	1.7	54.	11.3
D161080	5(B)	3	<.1	8.0	---	.068	1.5	5.7	.6	.5	<1.5	.5	6.9	5.67
D161081	7	4	<.1	5.2	---	.028	.8	5.0	.4	.6	<1.5	.3	3.2	5.00
D161082	10	4	<.1	13.6	---	.061	6.7	11.7	1.2	1.2	4.2	1.3	56.	14.8
D161083	10	3	<.1	5.5	---	.035	1.6	4.5	.2	.3	<1.5	.4	14.6	6.92

Sample No.	Thickness of sample interval feet	B	Ba	Be	Co	Cr	Ga	La	Mn	Mo	Nb	Ni	Sc	Sn	Sr	Ti	V	Y	Yb	Zn
UNIDENTIFIED COAL BEDS IN 12 CORES, NE WYO. AND SE MONT.																				
D160662	9(T)	50	500	<0.15	1.	2	1.	<5	15	2.	0.7	1.	1.	1.	200	150	7	1.	0.1	7
D160663	3(B)	20	200	.5	2.	5	2.	5	15	5.	1.5	2.	2.	<.5	200	500	20	3.	.3	10
D160666	7	30	150	<.15	.7	2	1.	<5	15	3.	<.7	.7	1.	.7	300	150	10	1.	.1	5
D160667	1	30	500	<.15	.7	2	1.	<5	20	10.	1.	1.	1.	1.5	300	200	7	1.5	.15	10
D160668	11(T)	30	300	<.15	.7	2	1.	<5	5	2.	1.	.7	.7	<.5	200	200	7	1.5	.15	10
D160669	10	20	300	<.15	.5	1.5	1.	<5	5	1.	<.7	.5	.5	<.5	200	100	5	.7	.07	3
D160670	3(B)	20	500	.2	1.	5	2.	5	7	3.	<.7	5.	1.	<.5	200	200	10	3.	.2	7
D160671	4	100	200	1.	5.	7	2.	5	5	3.	<.7	10.	2.	<.5	20	200	15	5.	.5	10
D160672	8(T)	50	200	.2	1.	5	2.	5	10	1.	1.5	5.	1.	<.5	50	200	15	5.	.5	10
D160673	10(B)	30	200	<.15	.3	1.5	1.	<5	20	.3	<.7	.7	.7	<.5	150	150	7	1.5	.15	5
D161073	10(T)	50	200	<.15	.7	5	1.5	<5	15	1.5	<.7	2.	1.5	<.5	200	200	10	1.5	.15	7
D161074	10(B)	50	200	<.15	1.	3	1.	<5	15	3.	<.7	5.	1.	1.5	200	150	10	2.	.2	5
D161075	1	50	200	2.	3.	3	5.	<5	150	3.	<.7	7.	2.	1.5	300	70	7	10.	.7	3
D161076	8(T)	50	200	<.15	<.3	1.5	1.	<5	50	.7	<.7	.7	<.5	1.5	200	200	5	<.7	<.1	10
D161077	10(B)	50	150	.15	<.3	1	.5	<5	15	.7	<.7	1.	.5	<.5	150	70	3	1.	.1	3
D161078	7	50	300	<.15	1.	3	1.	<5	20	.5	<.7	5.	1.	<.5	200	300	10	2.	.2	10
D161079	9(T)	30	300	.5	3.	10	2.	10	30	.7	<.7	10.	3.	<.5	300	300	30	5.	.5	15
D161080	5(B)	30	100	<.15	1.5	3	1.	5	5	.3	<.7	5.	1.	<.5	300	150	10	5.	.3	5
D161081	7	30	300	<.15	.5	1.5	.7	<5	3	.5	<.7	2.	.7	<.5	300	100	5	1.	.1	5
D161082	10	50	500	.1	5.	15	5.	<5	15	1.	<.7	7.	5.	<.5	700	500	50	5.	.5	15
D161083	10	30	200	<.15	1.	5	1.5	<5	10	<.3	<.7	3.	1.	<.5	700	700	10	1.5	.15	10

Table IX-4
EPA Analyses
Montana Coal

EPA Sample Number	Al %	Br.	V	Mn	Mg	Ti
72-009-443	1.00	22	7.8	27	0.02	100
72-009-444	0.22	9	3.4	11	0.05	110
72-009-445	0.44	53	15	13	0.06	130
72-009-446	0.59	38	27	16	0.16	380
72-009-447	0.21	6	8	7	0.03	180
72-009-448	0.86	27	9	34	0.41	200
72-009-449	0.96	43	8.3	58	0.42	660
72-009-450	0.74	9	7.4	101	0.20	430
72-009-451	0.74	33	3.6	91	0.19	330
72-009-452	0.24	24	2.3	70	0.14	130
72-009=453	0.59	9	1	80	0.48	150
72-009-454	1.91	110	20	120	1.1	1300
72-009-455	0.66	10	7.5	53	0.24	300
72-009-456	0.70	10	7.8	59	0.61	200
72-009-457	0.66	10	4.8	76	0.16	150
72-009-458	0.83	35	5.5	14	0.27	330
72-009-459	1.23	69	35	42	0.02	310

Table IX-5
EPA Analyses
Montana Coal Samples

	Lanthunum	Sodium	Samarium	Europium	Cobalt	Iron	Scandium	Hafnium	Chromium	Thorium	Terbium	Tantalium
Sample No.	La	Na	Sm	Eu	Co	Fe	Sc	Hf	Cr	Th	Tb	Ta
72-009-443	3.8	3500	0.44	.066	1.3	0.23	1.3	0.60	5.5	0.47	.085	0.14
-444	1.2	2600	0.17	.046	0.42	0.13	0.46	0.24	1.2	0.24	.29	.064
-445	4.2	3800	0.65	0.15	2.0	0.61	1.6	0.69	5.7	0.79	0.10	0.18
-446	4.1	2400	0.71	0.13	1.1	0.43	1.4	0.90	4.3	0.74	.006	0.21
-447	3.2	2200	0.54	.076	0.74	0.17	1.0	0.89	5.9	0.61	.062	0.10
-448	5.0	250	0.84	0.12	0.81	0.58	1.3	0.94	5.8	36	0.17	0.21
-449	4.1	220	0.63	0.11	0.68	0.70	1.2	1.1	3.9	1.3	.002	0.25
-450	3.8	150	0.55	.075	0.48	0.20	1.0	0.77	3.0	1.5	.065	0.24
-451	4.0	140	0.50	.085	0.40	.069	1.0	0.81	2.8	1.3	.056	0.26
-452	0.50	200	0.25	.028	0.32	.012	0.42	0.28	0.89	2.2	.017	.014
-453	1.7	140	0.16	.021	0.24	.012	0.31	0.31	0.91	0.82	.017	.068
-454	6.4	1300	1.8	0.31	3.8	2.45	3.6	2.1	14	4.1	0.27	0.78
-455	0.38	240	0.29	.050	0.88	.018	1.1	0.42	4.0	0.89	.021	0.16

	Lanthunum	Sodium	Samarium	Europium	Cobalt	Iron	Scandium	Hafnium	Chromium	Thorium	Terbium	Tantalium
Sample No.	La	Na	Sm	Eu	Co	Fe	Sc	Hf	Cr	Th	Tb	Ta
72-009-456	5.4	300	0.83	.086	0.83	0.34	0.80	0.73	2.8	1.0	.087	0.26
-457	8.5	250	1.1	0.18	1.6	1.38	1.8	1.2	7.4	1.5	0.13	0.32
-458	4.8	130	0.80	.097	0.68	0.36	0.69	0.77	2.5	1.2	.093	0.43

Table IX-6

U.S.B.M. Grand Forks Lab

MERCURY CONTENT OF NORTH DAKOTA COAL SAMPLES AND VARIOUS ASH FRACTIONS FROM TEST FURNACE RUNS

Average mercury content in ppb of:	Beulah	Savage	Big Horn
Coal	90	20	35
Ash deposit from combustion chamber	60	33	25
Deposits on simulated boiler tubes. Tube temperature 1000° F, gas temperature 2000° F:			
Outer sinter layer		41	20
Inner white layer		165	85
Fly ash collected in cyclone dust collector	125	235	
Fly ash collected in electrostatic precipitator	122		110

Table IX-7

ESSO Research and Engineering Company

—Areal distribution of the elements, in parts per million, of groups of bed samples

[0, below limit of detection]

Locality (fig. 2)	Beds averaged for the locality	Be	B	Ti	V	Cr	Co	Ni	Cu	Zn	Ga	Ge	Mo	Sn	Y	La
1	Mont-A1, Mont-CMT	2.0	93.4	778	10.6	8.5	6.6	11.2	9.7	23.2	13.2	14.9	0.58	3.9	[illegible]	[illegible]
2	Mont-B, Mont-Su	[illegible]	82.3	1,140	23.3	6.7	3.2	4.4	15.5	0	0	6.6	1.3	3.4	[illegible]	[illegible]
3	Mont-F	1.9	336	357	15.2	4.1	1.7	4.0	7.0	0	3.4	1.3	2.1	4.3	[illegible]	[illegible]
4	Mont-RB-F, Mont-O-F, Mont-P-1 to Mont-P-3	1.1	97.2	620	27.5	10.9	1.5	9.1	47.5	0	11.2	.6	2.6	.4	8.7	[illegible]
5	Mont-K₁-Rb, K₂-Rb, Mont-N-Ro, Mont-St-BM, Mont-Ke-CC	2.0	91.2	251	11.6	8.9	2.2	3.2	10.6	0	4.5	2.1	.9	.23	9.2	[illegible]
6	Mont-FC-3	.11	139	290	13.5	5.0	.60	3.6	10.5	0	1.3	0	1.3	1.0	2.8	[illegible]
8	Mont-[illegible] to Mont-[illegible]	1.7	....	....	14.6	16.2	3.0	2.7	9.2	0	6.4	0	2.0	....	15.9	[illegible]
9	ND-BN-N, ND-BN-20N, ND-YI-N	.57	78.1	208	8.3	3.7	2.2	2.7	7.6	0	3.0	2.0	2.4	0	8.8	5.4
10	ND-Cu-GC	1.6	201	95.1	5.3	3.0	1.8	2.9	2.8	0	.96	3.4	1.6	1.2	4.4	0
11-12	ND-Kh-Bo, ND-F-[illegible] to ND-F-[illegible]	1.1	....	....	13.4	8.4	3.0	10.8	[illegible]	241	3.0	.46	.50	....	13.3	12.[illegible]
14	Wyo-Mo-Mo	.12	....	....	8.0	2.6	.68	1.5	2.1	16.8	1.3	0	.16	0	1.2	0
15	Wyo-Ch-He-1 to Wyo-Ch-He-6	.36	....	....	20.5	12.9	3.4	11.9	14.9	0	4.7	0	2.7	0	[illegible]	[illegible]

TABLE IX - 8

Equivalent Uranium, Uranium, and Calculated Thoria,
Gray Goose Claim, Beaverhead County, Montana

Sample Number	Location	Description	Equivalent uranium (percent)	Uranium (percent)	Thoria (calculated percent)
AFT-S41-50	Small pit, Gray Goose No. 1 claim	Grab sample, biotite diorite pegmatite dike	0.025	0.002	0.1
AFT-S42-50	do.	do.	0.053	0.002	0.2
AFT-S44-50	Bulldozer trench, Gray Goose No. 1 claim	Grab Sample, biotite schist	0.003	0.001	0.01
AFT-S43-50	do.	Grab sample, quartz vein	0.032	0.003	0.1
AFT-S45-50	Small pit, Gray Goose No. 2 claim.	Grab sample, soil above a biotite-rich contact metamorphic zone	0.034	0.002	0.1
AFT-S51-50	Bulldozer trench, Gray Goose No. 2 claim	Grab sample, biotite schist	0.040	0.003	0.2
AFT-S50-50	do.	Grab sample, granite pegmatite	0.014	0.002	0.05

--Equivalent uranium, uranium, thoria, and calculated thoria, Last chance and Shady Tree claims, Beaverhead County, Montana

Sample number	Location	Description	Equivalent uranium (percent)	Uranium (percent)	Thoria (determined percent)	Thoria (calculated percent)
AFT-S24-50	Small pit, southern segment.	Chip sample across cherty lens.	0.10	0.003		0.5
AFT-S25-50	Small pit, southern segment.	1-foot chip sample of vein.	0.43	0.005		2.4
AFT-S26-50	South segment below bulldozer trench.	1-foot chip sample of vein.	0.44	0.004		2.4
AFT-S32-50	Bulldozer trench.	5-foot chip sample across footwall of vein.	0.15	0.002	0.79	0.8
AFT-S33-50	Bulldozer trench.	Chip sample across hanging wall of vein.	0.041	0.001		0.2
AFT-S34-50	Northern segment.	Chip sample across vein.	0.009	0.001		0.04
AFT-S35-50	South end, south segment.	Chip sample across vein.	0.014	0.001		0.07

--Equivalent uranium, uranium, and calculated thoria, Trapper No. 4 claim, Beaverhead County, Montana

Sample number	Location	Description	Equivalent uranium (percent)	Uranium (percent)	Thoria (calculated percent)
AFT-S60-50	Discovery pit.	Grab sample of fault gouge.	0.016	0.002	0.09
AFT-S61-50	do.	Chip sample across vein.	0.10	0.006	0.5
AFT-S63-50	East wall of bulldozer trench.	15-foot chip sample across fault gouge.	0.011	0.001	0.05
AFT-S64-50	Bulldozer trench floor.	Grab sample of iron oxide streaks in fault zone.	0.005	0.001	0.02

--Equivalent uranium, uranium, thoria, and calculated thoria, Trapper No. 1 claim, Beaverhead County, Montana

Sample Number	Location	Description	Equivalent uranium (percent)	Uranium (percent)	Thoria (percent)	Thoria (calculated percent)
-S37-50	Large outcrop.	Composite chip sample of south-dipping fracture surfaces in vein.	0.023	0.002		0.1
-S36-50	Northeast corner, large outcrop.	Chip sample of vein.	0.12	0.006	0.66	0.6
-S38-50	Bulldozer trench near discovery pit.	Chip sample across east part of vein.	0.13	0.006	0.56	0.7
-S39-50	Discovery pit.	Chip sample across west part of vein.	0.13	0.006	0.68	0.7
-S40-50	Large outcrop.	Composite chip sample of surface of vein.	0.029	0.002		0.1
-S46-50	Bulldozer trench below large outcrop.	Composite chip sample of hanging wall of vein.	0.014	0.001		0.07
-S47-50	Upper bulldozer trench.	Chip sample across vein.	0.025	0.001		0.1
-S48-50	Bulldozer trench below large outcrop.	Grab sample of gouge on hanging wall of quartz-limonite vein.	0.004	0.002		0.01
-S49-50	Upper bulldozer trench.	Grab sample of vein.	0.074	0.002		0.4

Table IX-9

C.T. & E. Co.

ELEMENT	Sample 72-10490 Rosebud Seam(1)	Sample 72-10491 McKay Seam(2)	Sample 72-10492 Robinson Seam(3)	Calculated Weighted Average
COBALT (Co)	3.60	0.35	1.20	1.85
CADMIUM (Cd)	1.80	0.53	0.69	1.06
VANADIUM (V)	7.70	5.80	5.80	6.51
NICKEL (Ni)	9.00	0.90	9.00	6.65
FLUORINE (F)	130.00	130.00	380.00	215.00
BERYLLIUM (Be)	0.70	2.00	2.00	1.52
MERCURY (Hg)	0.26	0.43	0.35	0.34
LEAD (Pb)	3.60	7.20	1.44	3.91
ARSENIC (As)	3.00	1.00	0.75	1.66
SELENIUM (Se)	0.08	0.30	0.08	0.14
ZINC (Zn)	22.00	33.00	13.00	22.15

(1) Total Footage 86.0' - Average Seam Thickness 17.2' (37.2%)
(2) Total Footage 67.0' - Average Seam Thickness 13.4' (29.0%)
(3) Total Footage 78.0' - Average Seam Thickness 15.6' (33.8%)

	Stray Seam #1	Stray Seam #2	Rosebud-McKay Seam	Robinson Seam	Weighted Average
Cobalt (Co)	12	11	13	8.3	11.32
Cadmium (Cd)	0.43	0.87	2.1	2.1	1.95
Vanadium (V)	48	33	25	11	22.04
Nickel (Ni)	30	30	30	15	25.14
Fluorine (F)	330	340	510	340	436.58
Beryllium (Be)	14	18	1.8	3.7	3.92
Mercury (Hg)	0.03	0.26	0.14	0.07	0.12
Lead (Pb)	6.2	5.7	8.6	2.9	6.47
Arsenic (As)	3.3	20	3.3	0.65	3.38
Selenium (Se)	1.4	1.1	1.1	0.22	0.83
Zinc (Zn)	170	45	45	45	51.13

Table No. 3 Hole No. 414

Cobalt (Co)	11	11	11	5.6	9.39
Cadmium (Cd)	0.66	0.87	0.66	1.7	0.98
Vanadium (V)	22	44	83	11	55.60
Nickel (Ni)	150	15	30	15	31.11
Fluorine (F)	120	110	680	340	509.53
Beryllium (Be)	7.4	7.4	1.8	1.8	2.49
Mercury (Hg)	0.06	0.30	0.07	0.14	0.11
Lead (Pb)	29	14	5.7	2.9	6.71
Arsenic (As)	6.3	17	1.3	2.5	3.00
Selenium (Se)	11	1.8	0.56	0.73	1.27
Zinc (Zn)	22	67	45	22	38.39

Table No. 4 Hole No. 12C

Cobalt (Co)			1.5	1.3	1.43
Cadmium (Cd)			3.9	4.6	4.14
Vanadium (V)			11	11	11.00
Nickel (Ni)			21	21	21.00
Fluorine (F)			120	70	102.74
Beryllium (Be)			0.09	0.20	0.13
Mercury (Hg)			0.18	0.18	0.18
Lead (Pb)			5.4	5.4	5.40
Arsenic (As)			6.5	2.0	4.95
Selenium (Se)			1.4	1.4	1.40
Zinc (Zn)			200	200	200.00

Colstrip Coal

ELEMENT	CONCENTRATION PPM WEIGHT
Cobalt (Co)	.4*
Cadmium (Cd)	.2
Vanadium (V)	.38
Nickel (Ni)	1.5
Fluorine (F)	50
Beryllium (Be)	20
Mercury (Hg)	.30
Lead (Pb)	.20
Arsenic (As)	.38
Selenium (Se)	.03
Zinc (Zn)	1.30

*Extracted from EIS on the proposed Montana Power Co. electrical generating plant at Colstrip, Montana, prepared by Dept. of Health and Environmental Sciences (Montana) March 1973.

Table IX-10

Beryllium Content of Coal and Coal Ash

U.S.G.S.

Coal

Position of beds	Sample	Bed	Beryllium in coal (ppm)
Rocky Mountain province			
Upper	Wyo-Oa-F_5	Finch No. 5	<0.1
	Wyo-Oa-F_4	Finch No. 4	<.1
to	Wyo-Oa-F_3	Finch No. 3	.8
	Wyo-Oa-F_2	Finch No. 2	.6
lower	Wyo-Oa-F_1	Finch No. 1	.1
Upper	Wyo-Ro-11	No. 11	12.7
	Wyo-Ro-9	No. 9	7.0
to	Wyo-Sup-9	No. 9	6.5
	Wyo-St-7½	No. 7½	3.1
	Wyo-Ro-7	No. 7	1.2
lower	Wyo-St-1	No. 1	.1
Northern Great Plains province			
Upper	Mont-P-1	Unnamed	0.8
	Mont-P-2	Flatness	.6
to	Mont-RB-F	do	1.1
	Mont-O-F	do	1.8
lower	Mont-P-3	Unnamed	1.5
Upper	Mont-OS-10501	H	<.5
	Mont-OS-10506	do	1.0
	Mont-OS-10508	do	<.2
	Mont-OS-10504	G	1.6
to	Mont-OS-10505	do	2.2
	Mont-OS-10502	F	6.0
	Mont-OS-10509	do	.8
	Mont-OS-10510	do	1.2
	Mont-OS-10503	E	2.5
lower	Mont-OS-10507	D	.5
Upper	ND-F-49877	Unnamed	.5
to	ND-F-49878	do	4.0
	ND-F-49874	Otter Creek (lower bed)	.8
lower	ND-F-49880	do	1.5
Upper	Wyo-Ch-He-1	Healy	.2
	Wyo-Ch-He-3	Unnamed	.8
to	Wyo-Ch-He-6	do	.5
	Wyo-Ch-He-4	do	.1
lower	Wyo-Ch-He-5	do	.1

Coal Ash

Province	Number of samples	Average ash (percent)	Average beryllium content of the ash	
			(ppm)	(clarkes)
Eastern	376	7.59	62	31
Interior	586	7.71	49	24.5
Northern Great Plains	189	9.83	27	13.5
Rocky Mountain	191	6.22	24	12
Total or average	1,342	7.74	46	23

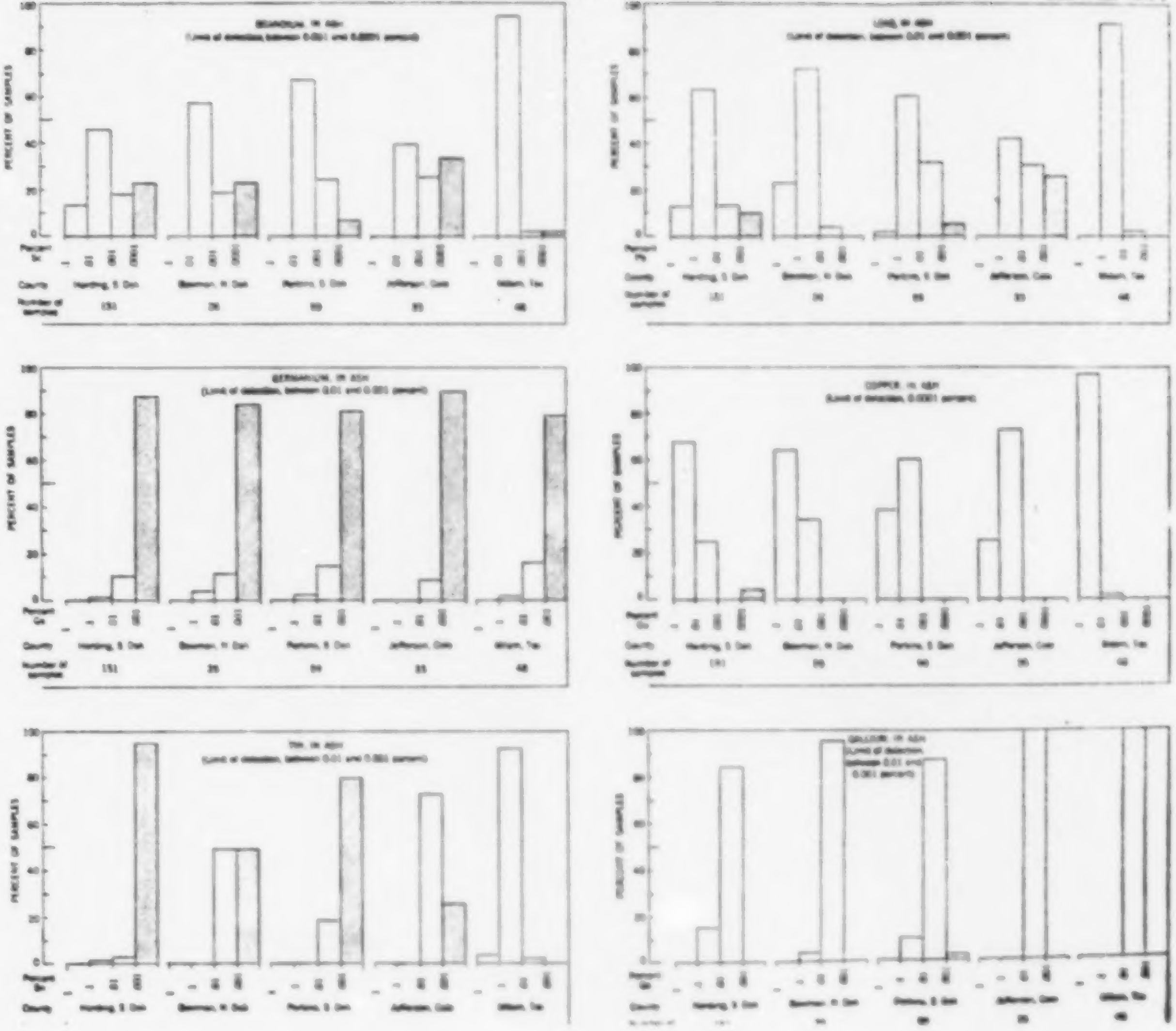
TABLE IX-11
U.S.G.S.

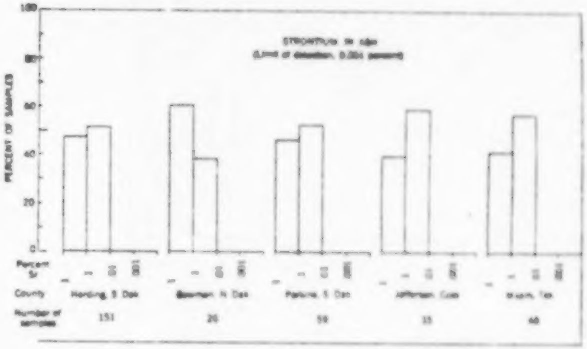
Southwest Energy Study
Trace Element Concentration in Coal

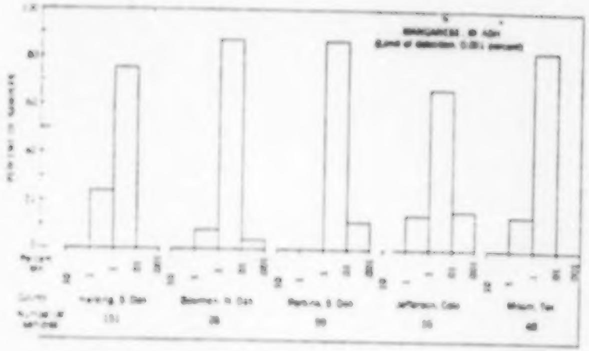
Location	Naughton					Rock Springs
Sample No.	D 152566	D 152567	D 152568	D 152569	D 152570	D 152573
Element, ppm						
Ash (%)	6.10	1.76	7.84	3.85	4.98	972
As	1	1	1	1	1	1
F	200	180	160	140	160	130
Hg	.02	.01	.03	.01	.02	.05
Sb	0.12	0.27	0.10	0.05	0.17	.49
Se	.5	.5	1.0	0.4	0.9	1.50
Te	.02	.05	.02	.02	.02	0.02
Tl	0.2	0.2	0.2	1.4	0.2	0.20
Eu	10	10	10	10	10	10
U	0.40	0.09	0.41	0.20	0.23	1.30
Cd	1.0	3.0	1.0	1.0	1.0	1.0
Cu	50	72	41	41	47	.02
Li	42	25	35	41	27	128
Zn	70	10	75	100	59	23
N (%)	--	--	1.50	--	--	1.20
S (%)	0.44	0.51	0.61	0.25	0.39	0.44
Ti	0.3	0.3	0.3	0.3	0.3	0.50
Mn	300	2000	200	150	700	100
B	1500	5000	1000	2000	1500	1500

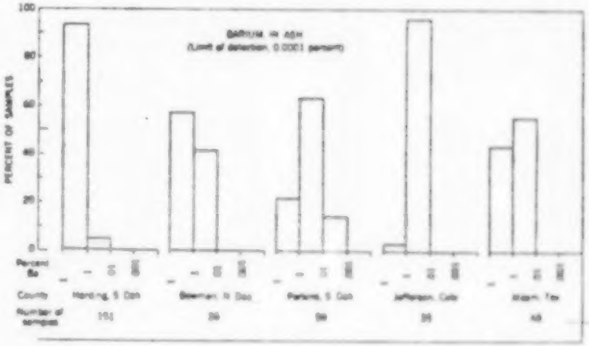
Sample No.	D 152566	D 152567	D 152568	D 152569	D 153570	D 15257[illegible]
Ba	3000	1000	1500	1500	3000	3000
Be	5	3	7	5	7	2
Ce	300	300	300	300	300	300
Co	15	70	15	15	15	7
Cr	70	70	70	50	70	70
Ga	30	20	30	30	20	20
Ge	0	300	0	0	0	0
La	70	70	--	70	--	70
Mo	7	7	--	7	7	10
Nb	20	20	20	20	20	20
Nd	150	--	--	150	--	150
Ni	70	150	30	30	50	15
Pb	30	30	30	30	30	30
Sc	15	10	10	10	15	15
Sr	1500	300	300	300	700	700
V	150	70	100	70	100	100
Y	70	30	30	30	30	30
Yb	5	2	3	3	3	3
Zr	150	150	150	150	150	150

Table IX-12
A.E.C.




STRONTIUM IN ASH
(Limit of detection, 0.001 percent)
PERCENT OF SAMPLES
Percent Sr
County
Harding, S Dak
Bowman, N Dak
Perkins, S Dak
Jefferson, Colo
Milam, Tex
Number of samples
151
26
59
35
48


MANGANESE IN ASH
(Limit of detection, 0.001 percent)
PERCENT OF SAMPLES
Percent Mn
County
Harding, S Dak
Bowman, N Dak
Perkins, S Dak
Jefferson, Colo
Milam, Tex
Number of samples
151
26
59
35
48


BARIUM IN ASH
(Limit of detection, 0.0001 percent)
PERCENT OF SAMPLES
Percent Ba
County
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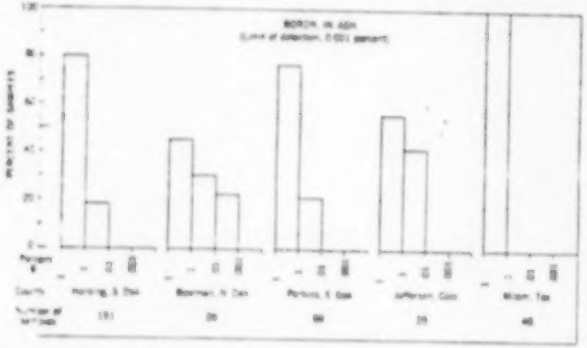
Bowman, N Dak
Perkins, S Dak
Jefferson, Colo
Milam, Tex
Number of samples
151
26
59
35
48


BORON IN ASH
(Limit of detection, 0.001 percent)
PERCENT OF SAMPLES
Percent B
County
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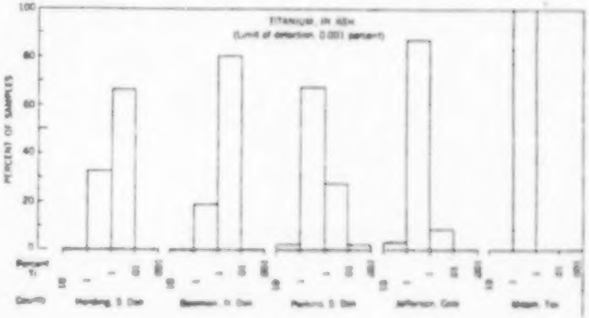
Bowman, N Dak
Perkins, S Dak
Jefferson, Colo
Milam, Tex
Number of samples
151
26
59
35
48


TITANIUM IN ASH
(Limit of detection, 0.001 percent)
PERCENT OF SAMPLES
Percent Ti
County
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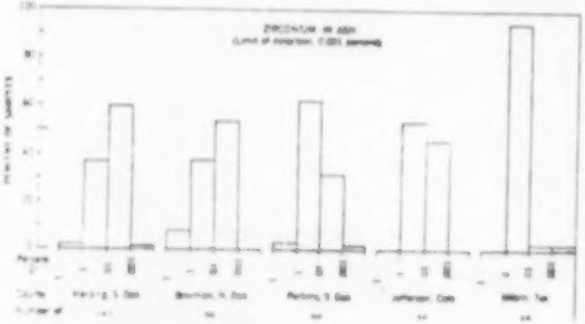
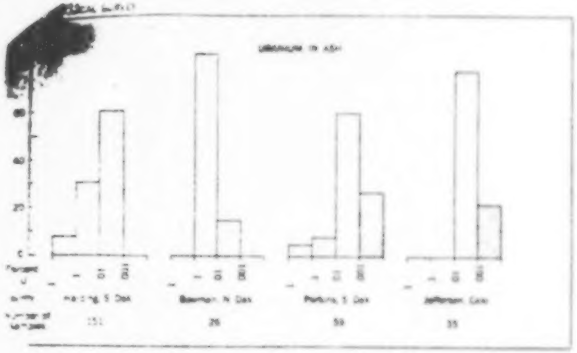
Bowman, N Dak
Perkins, S Dak
Jefferson, Colo
Milam, Tex


ZIRCONIUM IN ASH
(Limit of detection, 0.001 percent)
PERCENT OF SAMPLES
Percent Zr
County
Harding, S Dak
Bowman, N Dak
Perkins, S Dak
Jefferson, Colo
Milam, Tex
Number of samples


URANIUM IN ASH
Percent U
County
Number of samples
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Bowman, N. Dak
Perkins, S. Dak
Jefferson, Colo
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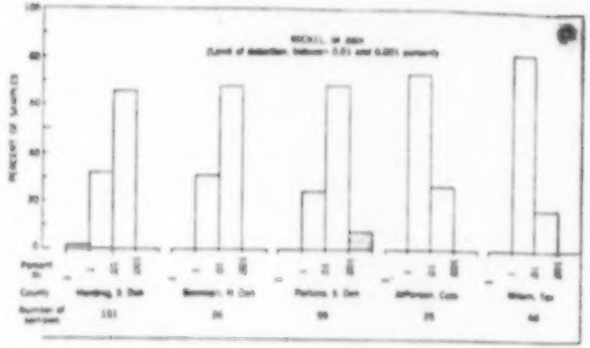
26
59
35


NICKEL IN ASH
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PERCENT OF SAMPLES
Percent Ni
County
Number of samples
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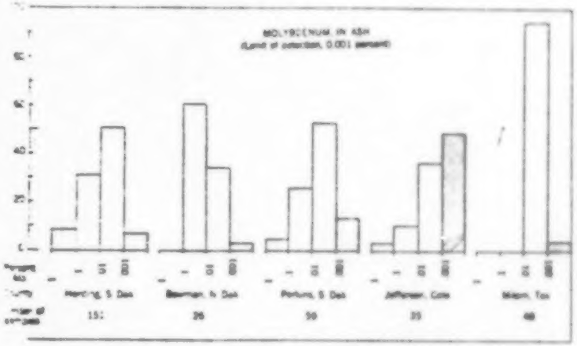
Bowman, N. Dak
Perkins, S. Dak
Jefferson, Colo
Milam, Tex
151
26
59
35
48


MOLYBDENUM IN ASH
(Limit of detection, 0.001 percent)
Percent Mo
County
Number of samples
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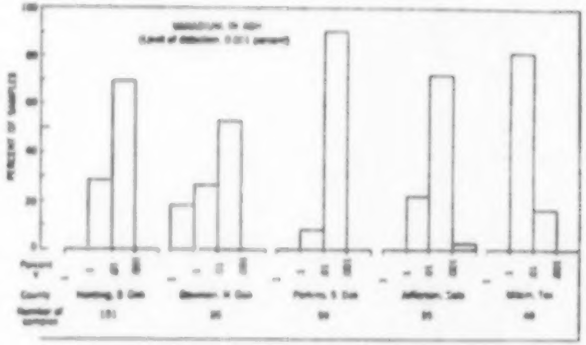
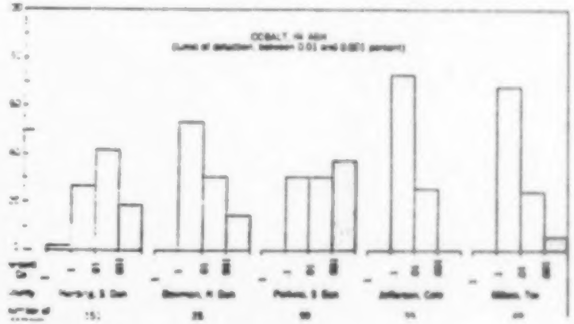
Bowman, N. Dak
Perkins, S. Dak
Jefferson, Colo
Milam, Tex
151
26
59
35
48


VANADIUM IN ASH
(Limit of detection, 0.001 percent)
PERCENT OF SAMPLES
Percent V
County
Number of samples
Harding, S. Dak
Bowman, N. Dak
Perkins, S. Dak
Jefferson, Colo
Milam, Tex
151
26
59
35
48


COBALT IN ASH
(Limit of detection, between 0.01 and 0.001 percent)
Percent Co
County
Number of samples
Harding, S. Dak
Bowman, N. Dak
Perkins, S. Dak
Jefferson, Colo
Milam, Tex
151
26
59

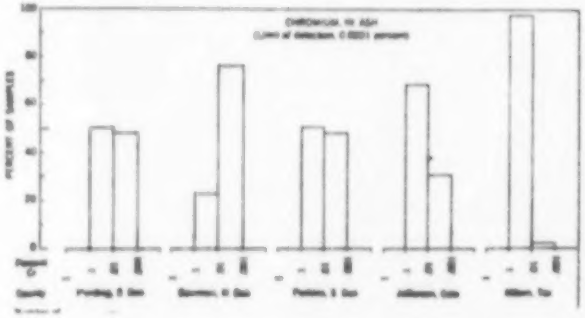

CHROMIUM IN ASH
(Limit of detection, 0.0001 percent)
PERCENT OF SAMPLES
Percent Cr
County
Harding, S. Dak
Bowman, N. Dak
Perkins, S. Dak
Jefferson, Colo
Milam, Tex

Table IX-13

United Power Association

Cooperative Power Association

Arsenic	6.40 ppm
Beryllium	0.54
Manganese	35.00
Cadmium	0.01
Nickel	0.5
Lead	0.5
Mercury	0.094

Table IX-14

Minnkota Power

ANALYTICAL RESULTS FOR TRACE ELEMENTS IN LIGNITE (CENTER, NORTH DAKOTA) *

Determination	ppm (Dry Coal Basis)
Antimony	6
Arsenic	5
Barium	1270
Beryllium	2
Bismuth	6
Boron	20
Cadmium	0.67
Chlorine	112
Copper	16
Fluorine	112
Lead	7
Manganese	60
Mercury	0.1
Nickel	13
Selenium	1.3
Vanadium	28
Zinc	9.8

*Analysis Report by Hazen Research Inc., Golden, Colorado, November 1972

Table IX-15

TRACE ELEMENTS IN U.S. COALS, (ppm), BY GEOGRAPHICAL REGION[1]

ESSO Research and Engineering Company

ELEMENT (variance) (3)	Range of Analysis, ppm on Coal			Wt. % on Ash	Comments
	Averages (2) by Region (1) and Area	90 + % Range for Beds (4) within Region	Bed Extremes (occurrence) (5)	Averages for States, by Region (6)	
Hazardous					
Be 5	2.0-3.1 2.5 .64-2.3 1.5	A .6-4.1 IE .6-7.6 IW .1-5.5 W <.1-3.1 N .12-3.9	11 (1:44)	A .001-.007 IE .001-.004 IW .000-.001 SW .0002-.001 N .000-.001	Wide variability from block to block within a bed. Regional effects observed, concentration higher near the edge of a bed or basin, less in center. Be higher in organic fraction of coal, low in associated mineral fraction.
F 3	50-120 50-100 65-120 65-160 65	A 10-190 IE 50-167 IW 50-120 SW 60-220 N 60-70			Mostly narrow range; high in some western areas.
As		A 3-59 I 8-45 SW 73	114 (1:15)	A 0 (33%)-.016 I 0 (39%)-.012 W 0 (88%)-.007	Not distinctive, marked local high concentrations (arsenopyrites), wide range in each area.
Se		SW .50-3.9			Very little data; associated with mineral fraction (selenopyrites) probably higher in eastern coals.
Cd		SW .0-.06		<.005	Very little data; regularly less than detection limit of .005% on ash by spectrographic analysis.
Hg 3	.12-.21 .13 .19 .07	A .07-.41 IE .04-.49 IW .19 SW .01-.25 N .07-.09	.60-1.15 (2:55) .47-.90 (2:76)		Widely distributed at low levels, except beds near Hg ore bodies can reach very high concentration; selected mineral specimens (lithotypes) of 1-33 ppm reported from Pa., W. Va., Wyo., Mont.
Pb 3		A 4-14 IE 8-14 IW 4 W 5-10 N 7	34 37 120-170	A .001-.008 .014-.337 (3:39) IE .007-.028 IW .003-.020 W .001-.004 N .002-.004	Narrow range except for beds near Pb ore bodies.

ELEMENT (variance) (3)		Range of Analysis, ppm on Coal			Wt. % on Ash	
		Averages (2) by Region (1) and Area	90 + % Range for Beds (4) within Region	Bed Extremes (occurrence) (5)	Averages for States, by Region (6)	Comments
Others (Coal Basis)						
B		22-55	A 4-56	72 (1:44)	A .014-.056	Wide variations esp. in bottom layer, from B picked up from soil by coal-forming plants during growth. Concentration high in low rank coals.
		96	IE 13-198	4 (1:47)	IE .069-.080	
	6	18-73	IW 2 5-180		IW .018-.083	
					SW .020-.070 .15-.20 (8:71)	
		116	N 78-201	356 (1:12)	N .034-.048	
V		19-25	A 2.4-44		A .023-.042	Not distinctive (i.e., no marked geographical correlations)
		35	IE 8.7-67	96,182 (2:44)	IE .030-.034	
	2	17-22	IW 4.7-44	69,71 (2:52)	IW .015-.038	
					SW .005-.015	
		16	N 5.3-29		N .009-.010	
Cr		11-15	A 4.1-25	32 (1:44)	A .014-.026	Not distinctive.
		20	IE 5-54		IE .018-.025	
	2	12-17	IW 4.4-38	61 (1:52)	IW .015-.030	
					SW .007-.010	
		7	N 2.6-19		N .002-.003	
Co	3.5	4.1-6.7	A .5-12	16,19 (2:73)	A .014-.021	Not distinctive
		3.8	IE 1.2-10		IE .013-.023	
	2	4.4-5.4	IW .4-16	44 (1:52)	IW .023-.055	Co/Ni may be associated with pyrites, as the sulfides
					SW .001-007	
		2.7	N .7-7		N .006	
Ni		9.7-20	A 2.4-37	46 (1:44)	A .013-.028	Not distinctive; picked up more easily than Co by coal-forming plants. May be increased markedly, with other trace elements, in weathered coals (X in Figure 4).
		15	IE 5-37	46 (1:34)	IE .017-.031	
		11-26	IW 1.1-47		IW .033-.077	
					W .005-.011	
		7	N 1.5-15		N .001-.003	
Cu		14-17	A 3.4-37		A .008-.016	Not distinctive; occasional high values found in selected mineral specimens (lithotypes).
		11	IE 3.1-25		IE .007-.010	
	1.5	11-13	IW 2.9-37		IW .006-.015	
			SW 1-15		W .005-.012	
		15	N 2.8-16	47 (1:12)	N .001-.003	

ELEMENT	(variance) (3)	Range of Analysis, ppm on Coal Averages (2) by Region (1) and Area	 90 + % Range for beds (4) within Region	 Bed Extremes (occurrence) (5)	Wt. % on Ash Averages for States, by Region (6)	Comments
Zn	5	4.4-12 46* 22-53* 59*	A 0-36 IE 0-53 IW 0-35 SW 1-17 N 0-23	 72-600 (5:34) 230,290 (2:52) 331 (1:12)	A .020-.029 IE .051-.120 IW .019-.133 W .010-.043 N .025-.034	*Older high values are suspect, because of frequency and ease of contamination of samples in the field. More accurate data show some correlations with high concentrations near Zn ore bodies.
Ga	4	4.1-6.8 4.1 1.4-3.7 5.5	A 1.3-12 IE 1.5-8 IW .5-7.3 N 1.0-13	 11,18 (2:34) 19 (1:52)	A .002-.010 IE .003-.004 IW .002-.007 SW .001-.005 N .002-.004	No geographical areas of concentration; low in the Arkansas/Oklahoma area, far from source rocks. Accumulates in fly ash, where normal ~60 ppm may be useful as a mineral source.
Ge	>10	3.3-9.6 13 1-22 1.6	A 0-18 IE .4-27 IW 0-30 N 0-7	 38 (1:34) 65,68 (2:52) 15 (1:12)	A .001-.006 IE .008-.014 IW .001-.013 W .001-.003 N .001-.003	High variability between top/bottom layers of coal and center of the bed; can give higher [illegible] for thin or lenticular beds. Coal fly ash (~250 ppm) may be a useful mineral source.
Mo	4	1.5-5.8 4.3 2.6-4.3 1.7	A .4-8.7 IE .6-8.5 IW 0-7.3 N .1-3.4	18,42 (2:44) 12-18 (3:34) 12,16 (2:52)	A .002-.012 IE .005-.008 IW .005-.013 W .001-.003 N .003-.004	Only element whose enrichment correlated with U in spot locations, in USGS/AEC studies; variance would change to 3 by excluding one extreme value (in Alabama) from average for A.
Sn	(3)	(.1)-.9 1.5 .6-1.6	A 0-2.1 IE .1-5 IW 0-5 N .2-4.3	 22 (1:47)	A .001-.006 IE .001-.005 IW .001-.002 W .001-.002 N .001	Uniform, small amounts; high values in occasional lithotypes.
Y	3	9.6-22 7.7 7.2-7.9 13	A 6.6-28 IE 1-13 IW 1.7-27 N 1.0-37	41,42 (2:44) 33 (1:34) 35,48 (2:52)	A .005-.022 IE .009-.014 IW .010-.013 W .005-.010 N .006	Y/La ratio is more significant than absolute values; ratio decreases linearly (3:1 to 1:1) with distance of coal bed from source rocks during formation.
La	3	8.5-11 5.1 2.9-7.2 9.5	A 0-25 IE .2-24 IW 0-37 N 0-22	 36 (1:34) 84 (1:52)	A .010-.018 IE .011-.017 IW .010-.013 W .005-.015 N .010	Quite uniform as a percent on ash.

ELEMENT (variance) (3)	Range of Analysis, ppm on Coal			Wt. % on Ash	
	Averages (2) by Region (1) and Area	90 + % Range for Beds (4) within Region	Bed Extremes (occurrence) (5)	Averages for States, by Region (6)	Comments
U		A 10	60, 70		-- Mostly none, or in bottom few inches only
		IE 10	80		-- Same
		W 10-160	620		-- Uraniferous coals average 30 ppm, thin top layers higher.
		N 50-240			-- Large tonnages of lignite at 80 ppm, occasional beds as high as 2-5% uranium or ash.
Others (Ash Basis)					
Li				A .014-.106	Variable, probably depending on water contact.
				IE .017-.039	
				IW .005-.030	
				W .010-.028	
				N .010-.022	
Sc				A .006-.014	Wider range in western coals. Coal ash is a possible source, in view of scarcity of ores.
				IE .007-.008	
				IW .004-.005	
				W .001-.009	
				N .003-.005	
Mn				A .003-.054	Uniformly present in small amounts; wide range in lithotypes.
				IE .020-.062	
				IW .015-.043	
				SW .005-.020 .070, .20 (2:71)	
				N .030-.046	
Sr				A .051-.154	Narrow range, usually correlates with Ca.
				IE .058-.070	
				IW .060-.075	
				W .040-.092	
				N .061-.066	
Ba				A .045-.127	Uniformly present; high values in lignites presumably related to regional Ba concentrations.
				IE .029-.047	
				IW .015-.100	
				SW .030-.500	
				N .265-.300	
Yb				.0003-.0011	Present widely in low amounts.
Bi				.0001-.0002	Uniformly present in very low amounts.

Table IX-16

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COMPARISON OF COALS FROM VARIOUS REGIONS OF THE UNITED STATES

Average minor-element contents, in parts per million, of coals from various regions of the United States

Element	Northern Great Plains province	Eastern Interior region	Appalachian region	Element	Northern Great Plains province	Eastern Interior region	Appalachian region
Be	1.5	2.5	2.5	Ga	5.5	4.1	4.9
B	116	96	25	Ge	1.6	13	5.8
Ti	590	450	340	Mo	1.7	4.3	3.5
V	16	35	21	Sn	.9	1.5	.4
Cr	7	20	13	Y	13	7.7	14
Co	2.7	3.8	5.1	La	9.5	5.1	9.4
Ni	7.2	15	14	Ash average (in weight percent)	13.42	6.16	6.11
Cu	15	11	15				
Zn	59	44	7.6				

Average minor-element contents, in parts per million, of coal from 3 areas of the Appalachian region

Area	Be	B	Ti	V	Cr	Co	Ni	Cu	Zn	Ga	Ge	Mo	Sn	Y	La
Northern (Ohio, Md., Pa.)	2.4	65	407	21	15	4.7	20	15	12	5.8	9.6	3.8	0.1	22	8.3
Central (Ky., Northern Tenn.)	3.1	22	340	19	11	4.1	9.7	14	4.4	4.5	3.3	1.5	.9	9.6	11
Southern (Ala.)	2.0	24	350	25	14	6.7	15	17	5.6	4.1	6.4	5.8	.3	13	8.8

Comparison of the average minor-element content of coal from the Western and Eastern regions of the Interior coal province

[In parts per million]

Element	Western region			Eastern region
	Oklahoma-Arkansas basin (32 samples)	Iowa, Missouri, North Oklahoma (12 samples)	Total Western region (44 samples)	(47 samples)
Be	0.64	2.3	1.1	2.5
B	18	73	33	96
Ti	250	250	250	450
V	17	22	18	35
Cr	12	17	13	20
Co	4.4	5.4	4.6	3.8
Ni	11	24	14	15
Cu	11	13	11	11
Zn	22	[1] 52	[1] 28	44
Ga	1.4	3.7	2.0	4.1
Ge	1.0	22	6.8	13
Mo	2.6	4.3	3.1	4.3
Sn	1.6	.6	1.3	1.5
Y	7.2	7.9	7.4	7.7
La	7.2	2.9	6.5	5.1
Ash	[2] 5.11	[2] 7.45	[2] 5.75	....

[1] High zinc samples Mo-T-M (loc. 5, fig. 2) and Mo-P-T (loc. 4, fig. 2) not included in average.
[2] Ash content, in weight percent.

Table IX-17

U.S.G.S.

	Clarke of the elements (percent)	Spectrographic sensitivity		Coal of northern Great Plains coal province				Average of coal beds of West Virginia	
				Average of individual analyses		Average of coal beds			
		Percent	Clarkes	Percent	Clarkes	Percent	Clarkes	Percent [1]	Clarkes
Be	0.0002	0.0001	0.5	0.0025	12.5	0.0018	9.0	0.0029	14.5
B	.001	.001	1.0	.15	150	.19	190	.037	37.0
Ti	.5	.0005	.001	.59	1.2	.65	1.3	.91	1.8
V	.015	.001	.07	.065	4.3	.015	1.0	.028	1.9
Cr	.02	.0001	.005	.02	1.0	.007	.35	.016	.8
Co	.0023	.0005	.22	.004	1.5	.0021	.9	.0079	3.4
Ni	.008	.0005	.06	.0087	1.1	.0064	.8	.037	4.6
Cu	.007	.0001	.014	.015	2.1	.013	1.9	.049	7.0
Zn	.01	.02	2.0	.018	1.8	.056	5.6	.043	4.3
Ga	.0015	.001	.67	.010	6.7	.0047	3.1	.018	12.0
Ge	.0001	.001	10.0	.074	740	.0022	22.0	.0076	76.0
Mo	.0001	.0005	5.0	.0025	25.0	.0016	16.0	.011	110
Sn	.004	.002	.5	.0027	.68	.0016	.4	.016	4.0
Y	.002	.001	.5	.021	10.5	.013	6.5	----------	----------
La	.004	.003	.75	.012	2.9	.011	2.8	.026	6.5
Ash	----------	----------	----------	10.28	----------	13.42	----------	[2] 10.2	----------

[1] Headlee and Hunter, 1955.

[2] Arithmetic averages of beds.

Element	Mont-B-6		Mont-CMT-1		Mont-CMT-3		Mont-CMT-4		ND-Co-GC-1			ND-Co-GC-6	
	Block	Vitrain	Block	Vitrain	Block	Vitrain	Block	Durain	Block	Vitrain	Fusain	Vitrain	Fusain
Be	2.8	2.9	2.1	1.5	3.0	2.0	4.1	2.0	0.4	0.05	1.1	0	1.8
B	62	------	28	102	67	65	82	------	------	------	------	------	------
Ti	1,100	------	210	180	800	1,250	400	------	------	------	------	------	------
V	28	16	6.9	10	5.7	8.8	16	39	44	25	54	2.2	9
Cr	8.2	4.9	6.3	7.6	2.8	5.5	8.2	12	8.7	18	11	.9	8
Co	2.8	1.6	2.5	1.6	2.7	11	1.6	0	0	1.0	0	.9	.9
Ni	2.8	1.2	21	14	5.3	6.3	4.9	3.9	1.7	5.0	2.0	1.3	1.8
Cu	14	3.6	2.8	13	3.1	5.2	8.6	20	6.1	8.0	5.4	1.8	7.2
Ga	14	1.9	5.9	6.8	18	21	8.2	9.6	8.7	5.0	1.1	2.2	2.7
Ge	11	12	21	135	40	68	5.7	0	0	1.3	0	0	0
Mo	2.8	0	2.8	1.2	0	0	.8	0	2.6	.8	2.3	.9	1.8
Sn	5.5	0	0	3.1	1.3	1.3	0	0	------	------	------	------	------
Y	28	16	14	17	24	25	16	50	17	------	33	0	18
La	41	0	7.0	2.9	0	5.0	16	98	8.7	------	11	2.2	8.4

[0, below limit of detection]

Bed	Coals	Ash (percent)	Be	B	Ti	V	Cr	Co	Ni	Cu	Ga	Ge	Mo	Y	La
Big Sandy field, Montana															
Unnamed, above Flatness bed	Mont-P-1	26.48	0.79	132	1,580	53	19	1.9	2.9	185	21	0	2.7	7.9	21
Flatness	Mont-P-2	13.60	.88	69	852	14	9.7	1.4	1.4	8.5	6.6	0	2.8	5.5	12
Do	Mont-O-F	5.39	1.5	133	332	26	5.1	1.3	[illegible]	20	3.1	2.5	2.3	11	18
Do	Mont-RB-F	4.99	1.1	137	337	16	3.7	1.1	2.1	12	2.9	.5	2.1	7.9	15
Unnamed, below Flatness bed	Mont-P-3	29.00	1.8	15	2,320	29	17.4	2.3	2.9	16	23	0	2.9	12	20
Girard field, Montana															
H	Mont-GS-10501	59.2	0	......	......	59	178	12	12	12	18	0	0	41	0
H	Mont-GS-10506	10.0	1	......	......	9.0	10	4.0	4.0	6.0	5.0	0	2.0	10	0
H	Mont-GS-10508	14.1	0	......	......	0	.4	0	1.0	4.2	0	0	0	0	0
G	Mont-GS-10504	7.8	1.6	......	......	2.7	.2	0	.7	3.1	2.3	0	3.1	7.6	0
G	Mont-GS-10505	18.2	3.2	......	......	6.8	.8	3.2	5.0	11	6.8	0	4.9	49	0
F	Mont-GS-10502	18.9	6.4	......	......	32	.5	3.3	3.2	9.5	4.8	0	3.2	16	0
F	Mont-GS-10509	14.1	.9	......	......	4.2	.4	0	.4	4.2	4.2	0	4.2	7.1	0
F	Mont-GS-10510	24.2	1.2	......	......	13	0	4.8	4.8	22	9.7	0	2.4	0	0
E	Mont-GS-10503	25.8	2.5	......	......	13	2.0	2.5	2.0	13	10	0	0	25	0
D	Mont-GS-10507	9.8	.6	......	......	7.8	0	.6	3.9	7.6	3.9	0	0	0	0
Square Buttes field, North Dakota															
Unnamed, 100 ft above Otter Creek bed	ND-F-49877	10.5	0.53	......	......	7.4	11	10	21	11	2.1	0	0	32	21
Unnamed, 45 ft above Otter Creek bed	ND-F-49878	20.0	4	......	......	20	16	4	40	16	6	0	0	20	40
Otter Creek, lower bed	ND-F-49874	7.8	.76	......	......	7.6	5.3	.76	1.5	16	1.5	0	0	7.6	7.5
Do	ND-F-49880	21.1	1.5	......	......	13	11	2.1	6.3	5.4	4.2	0	0	0	0
Buffalo field, Wyoming															
Healy	Wyo-Ch-He-1	23.4	0.21	......	......	47	19	4.7	23	19	4.7	0	4.7	......	......
Unnamed 24 ft below Healy bed	Wyo-Ch-He-3	17.4	.87	......	......	12	5.2	3.5	17	14	3.8	0	3.5	......	......
Unnamed, 110 ft below Healy bed	Wyo-Ch-He-6	26.7	.51	......	......	25	21	8.1	21	23	7.7	0	5.1	......	......
Unnamed, 190 ft below Healy bed	Wyo-Ch-He-4	14.4	.09	......	......	13	12	1.6	4.8	14	2.9	0	1.6	......	......
Unnamed, 335 ft below Healy bed	Wyo-Ch-He-5	9.8	.10	......	......	6.7	2.9	.95	2.9	8.7	.95	0	.95	......	......

Table IX-18

U.S.G.S.

STATE: OF MONTANA

COUNTY	SEAM	MOISTURE A.R.	ASH A.R.	ASH DRY	SULFUR A.R.	SULFUR DRY	SULFUR MAF	BTU A.R.	BTU DRY	BTU MAF	NO. OF
BIG HORN	693	23.8	3.2	4.6	.2	.4	.4	8,230	11,550	12,120	1
	799	23.9	3.4	4.5	.3	.4	.4	9,540	12,540	13,130	13
	COUNTY TOTAL	24.1	3.4	4.5	.3	.4	.4	9,480	12,490	13,030	17
CARTER	799	40.1	10.7	18.0	1.0	1.8	2.1	5,910	9,860	12,030	2
	COUNTY TOTAL	40.1	10.7	18.0	1.0	1.8	2.1	5,910	9,850	12,030	2
CUSTER	308	34.3	8.4	12.9	.5	.8	.9	6,980	10,620	12,200	1
	322	29.1	15.0	21.2	.5	.8	1.0	6,660	9,400	11,920	1
	330	33.6	9.1	13.8	.5	.8	.9	6,850	10,310	11,960	2
	799	29.8	7.1	10.2	.4	.6	.6	7,700	10,960	12,210	13
	COUNTY TOTAL	30.4	7.9	11.4	.4	.6	.6	7,470	10,730	12,110	17
DANIELS	376	41.3	9.2	15.7	.5	.9	1.0	5,680	9,670	11,470	1
	799	33.6	8.7	13.2	1.1	1.8	2.0	6,670	10,040	11,570	2
	COUNTY TOTAL	36.2	8.9	14.0	.9	1.5	1.7	6,330	9,920	11,530	3
DAWSON	336	33.0	5.4	8.2	.2	.4	.4	7,400	11,050	12,030	1
	345	33.7	6.8	10.3	.5	.8	.8	7,090	10,690	11,920	1
	389	31.5	6.3	9.2	.6	.9	.9	6,880	10,040	11,060	1
	799	33.6	7.3	11.1	.9	1.4	1.5	7,120	10,720	12,060	13
	COUNTY TOTAL	33.4	7.1	10.7	.7	1.2	1.3	7,120	10,690	11,970	16
FALLON	799	40.1	10.7	18.0	1.0	1.0	2.1	5,910	9,860	12,030	2
	COUNTY TOTAL	40.1	10.7	18.0	1.0	1.8	2.1	5,910	9,860	12,030	2
GARFIELD	799	29.8	12.4	17.8	.4	.6	.7	7,210	10,270	12,490	2
	COUNTY TOTAL	29.8	12.4	17.8	.4	.6	.7	7,210	10,270	12,490	2
MCCONE	380	30.1	7.7	11.1	.5	.8	.8	7,600	10,870	12,230	3
	COUNTY TOTAL	30.1	7.7	11.1	.5	.8	.8	7,600	10,870	12,230	3
MUSSELSHELL	780	11.9	8.8	10.0	.4	.5	.5	10,930	12,460	13,840	423
	799	11.1	9.4	10.6	.4	.5	.5	10,870	12,230	13,630	8
	805	15.1	8.6	10.2	.8	1.0	1.1	10,500	12,370	13,770	7
	806	15.2	6.9	8.2	.5	.7	.7	10,590	12,480	13,590	24
	807	19.2	7.9	9.8	.8	1.0	1.1	9,600	12,000	13,300	134
	COUNTY TOTAL	13.7	8.5	9.9	.5	.6	.6	10,660	12,350	13,710	601

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STATE: 30 MONTANA

COUNTY		SEAM	MOISTURE A.R.	ASH A.R.	ASH DRY	SULFUR A.R.	SULFUR DRY	SULFUR MMAF	BTU A.R.	BTU DRY	BTU MMAF	[illegible]
POWDER RIVER		291	32.0	5.9	8.8	.2	.3	.3	7,650	11,230	12,330	3
		300	29.7	5.8	8.3	.4	.6	.6	7,900	11,240	12,250	[illegible]
		302	31.0	7.8	11.4	.4	.7	.7	7,550	10,950	12,350	3
		304	30.7	5.0	8.4	.2	.3	.3	7,770	11,220	12,250	3
		524	35.2	4.0	6.2	.3	.5	.5	6,930	10,670	11,400	1
		526	30.1	7.3	10.5	.5	.8	.8	7,800	11,160	12,470	5
		799	31.8	6.2	9.2	.2	.3	.3	7,630	11,190	12,320	14
	COUNTY TOTAL		30.8	6.2	9.1	.3	.5	.5	7,730	11,180	12,290	41
PRAIRIE		799	30.6	6.0	8.7	.4	.6	.6	7,840	11,290	12,370	27
	COUNTY TOTAL		30.6	6.0	8.7	.4	.6	.6	7,840	11,290	12,370	27
RICHLAND		304	27.3	3.9	5.4	.4	.6	.6	9,020	12,410	13,110	1
		315	27.3	4.5	6.3	.5	.8	.8	8,850	12,170	12,990	1
		337	36.5	6.6	10.4	.8	1.4	1.5	7,150	11,260	12,570	1
		342	38.3	5.9	9.7	.4	.8	.8	6,710	10,890	12,040	1
		345	38.3	5.9	9.7	.4	.8	.8	6,880	11,150	12,350	1
		371	23.9	7.0	9.3	.6	.8	.8	9,160	12,040	13,270	1
		373	23.7	11.9	15.7	.6	.8	.9	8,080	10,590	12,560	1
		524	26.5	6.8	9.3	1.8	2.5	2.7	8,080	11,010	12,140	1
		693	28.7	4.2	5.9	.2	.4	.4	8,630	12,100	12,860	[illegible]
		698	28.9	3.2	4.6	.2	.4	.4	8,230	11,530	12,130	1
		799	35.9	6.0	9.5	.4	.7	.7	7,090	11,060	12,220	43
	COUNTY TOTAL		34.9	6.0	9.3	.5	.8	.8	7,250	11,140	12,280	53
ROOSEVELT		799	38.9	6.0	9.9	.6	1.0	1.1	6,170	10,090	11,200	9
	COUNTY TOTAL		38.9	6.0	9.9	.6	1.0	1.1	6,170	10,090	11,200	9
ROSEBUD		799	27.7	5.1	7.1	.4	.6	.6	8,710	12,050	12,970	8
		808	23.9	8.1	10.7	.6	.8	.8	8,930	11,730	13,140	8
	COUNTY TOTAL		25.8	6.6	8.9	.5	.7	.7	8,820	11,890	13,050	16
SHERIDAN		799	38.0	6.6	10.7	.3	.6	.6	6,350	10,250	11,470	10
	COUNTY TOTAL		38.0	6.6	10.7	.3	.6	.6	6,350	10,250	11,470	10
TREASURE		799	19.8	14.4	18.0	1.5	1.9	2.3	8,500	10,700	13,050	1
	COUNTY TOTAL		19.8	14.4	18.0	1.5	1.9	2.3	8,500	10,700	13,050	1
VALLEY		375	42.7	8.7	15.2	.5	1.0	1.1	5,640	9,840	11,610	1
		376	37.5	6.1	9.8	.3	.5	.5	6,580	10,530	11,670	1
		799	38.9	6.5	10.7	.5	.9	1.0	6,130	10,030	11,230	15
	COUNTY TOTAL		39.0	6.6	10.9	.5	.9	1.0	6,130	10,050	11,270	17

TABLE AVERAGE ANALYSIS OF COAL BY STATE, COUNTY AND SEAM

STATE: 30 MONTANA

COUNTY	SEAM	MOISTURE A.R.	ASH A.R.	ASH DRY	SULFUR A.R.	SULFUR DRY	SULFUR M&AF	BTU A.R.	BTU DRY	BTU M&AF	NO. OF ANAL
WIBAUX	389	39.4	8.7	14.4	.9	1.5	1.7	6,100	10,070	11,760	2
	COUNTY TOTAL	39.4	8.7	14.4	.9	1.5	1.7	6,100	10,070	11,760	2
YELLOWSTONE	799	20.7	7.7	9.8	.5	.7	.7	8,890	11,210	12,420	19
	COUNTY TOTAL	20.7	7.7	9.8	.5	.7	.7	8,890	11,210	12,420	19
	STATE TOTAL	15.6	9.3	11.1	1.0	1.2	1.3	10,010	11,850	13,340	1420

1/ As Received

2/ Moisture & Ash Free

TABLE AVERAGE ANALYSIS OF COAL BY STATE, COUNTY AND SEAM

STATE: 33 NORTH DAKOTA

COUNTY	SEAM	MOISTURE A.R.	ASH A.R.	ASH DRY	SULFUR A.R.	SULFUR DRY	SULFUR M&AF	BTU A.R.	BTU DRY	BTU M&AF	NO. OF ANAL
ADAMS	799	33.1	10.5	15.7	1.2	1.8	2.1	7,030	10,590	12,560	34
	COUNTY TOTAL	33.1	10.5	15.7	1.2	1.8	2.1	7,030	10,590	12,560	34
BILLINGS	799	38.5	6.2	10.1	.8	1.4	1.5	6,350	10,320	11,480	6
	COUNTY TOTAL	38.5	6.2	10.1	.8	1.4	1.5	6,350	10,320	11,480	6
BOWMAN	799	43.4	6.6	11.7	.8	1.5	1.6	6,120	10,810	12,240	8
	COUNTY TOTAL	43.4	6.6	11.7	.8	1.5	1.6	6,120	10,810	12,240	8
BURKE	799	33.4	7.9	11.9	.3	.6	.6	7,260	10,900	12,370	612
	COUNTY TOTAL	33.4	7.9	11.9	.3	.6	.6	7,260	10,900	12,370	612
BURLEIGH	799	35.1	6.2	9.7	.6	1.0	1.1	7,100	10,950	12,120	115
	COUNTY TOTAL	35.1	6.2	9.7	.6	1.0	1.1	7,100	10,950	12,120	115
DIVIDE	799	32.0	7.8	11.6	.4	.7	.7	7,510	11,050	12,500	233
	COUNTY TOTAL	32.0	7.8	11.6	.4	.7	.7	7,510	11,050	12,500	233
DUNN	799	40.6	7.0	11.9	.6	1.1	1.2	6,310	10,630	12,060	25
	COUNTY TOTAL	40.6	7.0	11.9	.6	1.1	1.2	6,310	10,630	12,060	25
GOLDEN VALLEY	799	41.3	5.8	9.9	.6	1.1	1.2	6,330	10,790	11,970	3
	COUNTY TOTAL	41.3	5.8	9.9	.6	1.1	1.2	6,330	10,790	11,970	3
GRANT	799	34.5	10.4	15.9	1.6	2.5	2.9	6,840	10,440	12,410	19
	COUNTY TOTAL	34.5	10.4	15.9	1.6	2.5	2.9	6,840	10,440	12,410	19
HETTINGER	799	39.6	8.9	14.9	1.3	2.2	2.5	6,340	10,490	12,330	13
	COUNTY TOTAL	39.6	8.9	14.9	1.3	2.2	2.5	6,340	10,490	12,330	13
MCKENZIE	799	42.7	5.0	8.9	.4	.7	.7	6,330	11,040	12,120	5
	COUNTY TOTAL	42.7	5.0	8.9	.4	.7	.7	6,330	11,040	12,120	5

Discussion Draft 4/74

TABLE 11 . AVERAGE ANALYSIS OF COAL BY STATE, COUNTY AND SEAM

STATE: 33 NORTH DAKOTA

COUNTY	SEAM	MOISTURE A.R.	ASH A.R.	ASH DRY	SULFUR A.R.	SULFUR DRY	SULFUR M&AF	BTU A.R.	BTU DRY	BTU M&AF	NO. OF ANAL
MCLEAN	799	38.7	6.4	10.5	.4	.8	.8	6,620	10,800	12,070	44
	COUNTY TOTAL	38.7	6.4	10.5	.4	.8	.8	6,620	10,800	12,070	44
MERCER	799	33.8	6.8	10.4	.5	.9	1.0	7,200	10,880	12,140	723
	COUNTY TOTAL	33.8	6.8	10.4	.5	.9	1.0	7,200	10,880	12,140	723
MORTON	799	39.0	8.0	13.2	1.0	1.7	1.9	6,430	10,540	12,150	38
	COUNTY TOTAL	39.0	8.0	13.2	1.0	1.7	1.9	6,430	10,540	12,150	38
MOUNTRAIL	799	43.1	3.6	6.4	.2	.4	.4	6,440	11,310	12,080	1
	COUNTY TOTAL	43.1	3.6	6.4	.2	.4	.4	6,440	11,310	12,080	1
OLIVER	799	36.5	10.3	16.3	.8	1.4	1.6	6,410	10,100	12,070	20
	COUNTY TOTAL	36.5	10.3	16.3	.8	1.4	1.6	6,410	10,100	12,070	20
RENVILLE	799	35.2	6.3	9.8	.9	1.5	1.6	7,090	10,940	12,130	2
	COUNTY TOTAL	35.2	6.3	9.8	.9	1.5	1.6	7,090	10,940	12,130	2
SLOPE	799	42.5	6.3	11.0	1.3	2.4	2.6	5,950	10,350	11,630	1
	COUNTY TOTAL	42.5	6.3	11.0	1.3	2.4	2.6	5,950	10,350	11,630	1
STARK	799	41.1	8.5	14.6	1.1	1.9	2.2	6,150	10,440	12,220	14
	COUNTY TOTAL	41.1	8.5	14.6	1.1	1.9	2.2	6,150	10,440	12,220	14
WARD	799	37.2	5.5	8.8	.1	.3	.3	6,790	10,820	11,860	899
	COUNTY TOTAL	37.2	5.5	8.8	.1	.3	.3	6,790	10,820	11,860	899
WILLIAMS	799	41.0	6.3	10.8	.5	.9	1.0	6,420	10,880	12,200	38
	COUNTY TOTAL	41.0	6.3	10.8	.5	.9	1.0	6,420	10,880	12,200	38
	STATE TOTAL	35.1	6.8	10.5	.4	.7	.7	7,050	10,860	12,130	2064

TABLE . AVERAGE ANALYSIS OF COAL BY STATE, COUNTY AND SEAM

STATE: 46 SOUTH DAKOTA

COUNTY	SEAM	MOISTURE	ASH		SULFUR			BTU			NO. OF
		A.R.	A.R.	DRY	A.R.	DRY	M&AF	A.R.	DRY	M&AF	ANAL
CORSON	799	35.9	7.4	11.6	.5	.9	1.0	6,980	10,890	12,320	6
	COUNTY TOTAL	35.9	7.4	11.6	.5	.9	1.0	6,980	10,890	12,320	6
DEWEY	275	37.2	6.6	10.6	.4	.7	.7	6,900	11,000	12,300	4
	799	35.5	7.4	11.5	.5	.8	.9	7,020	10,890	12,300	18
	COUNTY TOTAL	35.8	7.3	11.4	.5	.8	.9	7,000	10,910	12,310	22
HARDING	799	38.0	10.9	17.6	1.3	2.2	2.6	5,660	9,130	11,080	14
	COUNTY TOTAL	38.0	10.9	17.6	1.3	2.2	2.6	5,660	9,130	11,080	14
MEADE	799			14.2		2.0	2.3		10,560	12,300	1
	COUNTY TOTAL			14.2		2.0	2.3		10,560	12,300	1
PERKINS	799	30.7	12.1	17.6	1.3	2.0	2.4	7,270	10,490	12,720	3
	COUNTY TOTAL	30.7	12.1	17.6	1.3	2.0	2.4	7,270	10,490	12,720	3
	STATE TOTAL	36.2	8.8	13.8	.8	1.3	1.5	6,590	10,330	11,930	45

TABLE AVERAGE ANALYSIS OF COAL BY STATE, COUNTY AND SEAM

STATE: 5? [illegible]

COUNTY	SEAM	MOISTURE A.R.	ASH A.R.	ASH DRY	SULFUR A.R.	SULFUR DRY	SULFUR MMAF	BTU A.R.	BTU DRY	BTU MMAF	NO. OF ANAL
CAMPBELL	701	33.9	5.0	7.6	.3	.5	.5	7,810	11,820	12,790	4
	706	31.3	7.0	10.3	1.4	2.1	2.3	7,810	11,370	12,655	4
	708	28.2	8.1	11.3	.9	1.3	1.4	8,050	11,210	12,630	2
	787	32.3	5.8	8.7	.5	.8	.8	7,930	11,720	12,840	10
	951	30.2	6.8	9.8	.5	.8	.8	8,070	11,560	12,810	25
	COUNTY TOTAL	31.0	6.5	9.5	.6	.9	.9	8,000	11,590	12,810	45
CONVERSE	799	27.2	5.8	8.1	.3	.5	.5	8,450	11,610	12,630	23
	COUNTY TOTAL	27.2	5.8	8.1	.3	.5	.5	8,450	11,610	12,630	23
CROOK	799	22.2	8.8	11.4	3.5	4.6	5.1	8,930	11,480	12,950	14
	COUNTY TOTAL	22.2	8.8	11.4	3.5	4.6	5.1	8,930	11,480	12,950	14
JOHNSON	691	28.5	5.7	8.1	.5	.8	.8	7,940	11,110	12,000	7
	799	25.8	8.6	11.6	.9	1.3	1.4	8,090	10,900	12,330	10
	977	27.9	9.7	13.5	.5	.8	.9	7,530	10,440	12,070	3
	COUNTY TOTAL	27.0	7.7	10.6	.8	1.1	1.2	7,940	10,880	12,170	20
NATRONA	799	24.5	11.1	14.8	.6	.8	.9	7,850	10,400	12,210	8
	COUNTY TOTAL	24.5	11.1	14.8	.6	.8	.9	7,850	10,400	12,210	8
NIOBRARA	799	29.9	7.2	10.4	.7	1.1	1.2	7,660	10,930	12,190	1
	COUNTY TOTAL	29.9	7.2	10.4	.7	1.1	1.2	7,660	10,930	12,190	1
SHERIDAN	002	22.8	4.4	5.8	.3	.5	.5	9,410	12,200	12,940	254
	691	27.7	7.5	10.4	.4	.6	.6	7,780	10,760	12,015	2
	695	23.1	4.2	5.5	.4	.6	.6	9,350	12,150	12,860	67
	697	24.4	4.7	6.3	.4	.6	.6	9,020	11,930	12,730	8
	698	24.7	4.6	6.2	.3	.5	.5	8,900	11,820	12,600	1
	701	26.3	5.3	7.3	.6	.9	.9	8,340	11,320	12,210	2
	702	29.8	5.6	8.0	1.3	1.9	2.0	7,830	11,160	12,130	3
	783	21.0	4.5	5.7	.4	.6	.6	9,720	12,310	13,050	1700
	784	24.9	4.7	6.3	.4	.6	.6	9,020	12,010	12,820	5
	786	24.5	4.3	5.8	.5	.7	.7	9,220	12,210	12,950	10
	787	23.5	4.8	6.3	1.3	1.8	1.9	9,010	11,720	12,570	1
	799	22.7	5.2	6.8	.3	.5	.5	9,330	12,070	12,950	20
	952	23.6	3.2	4.3	.3	.4	.4	9,520	12,460	13,020	5
	COUNTY TOTAL	21.4	4.4	5.7	.4	.6	.6	9,650	12,280	13,020	21[illegible]

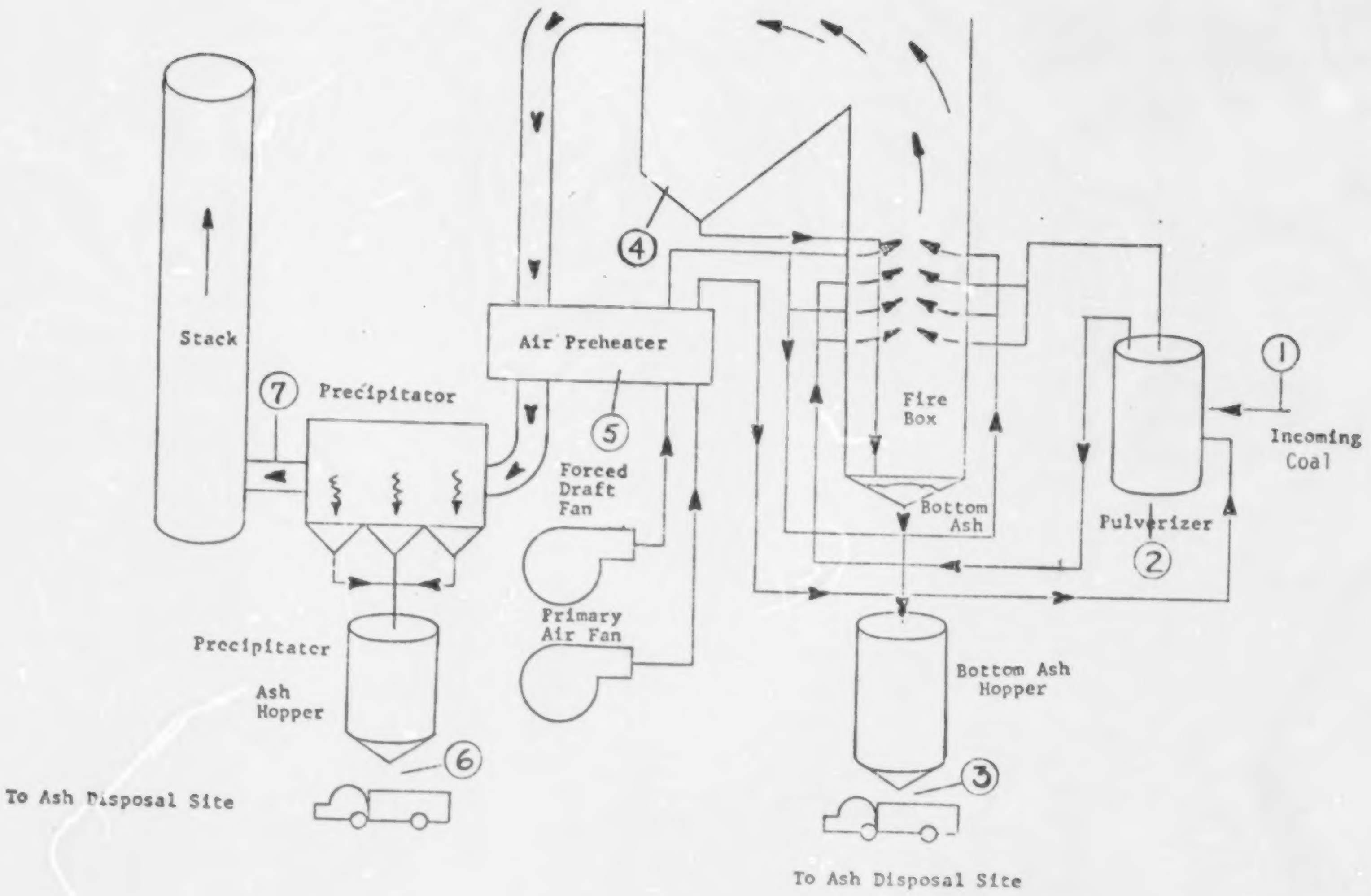

Stack
⑦
Precipitator
Air Preheater
④
⑤
Forced Draft Fan
Primary Air Fan
Precipitater Ash Hopper
⑥
To Ash Disposal Site
Fire Box
Bottom Ash
Bottom Ash Hopper
③
To Ash Disposal Site
Pulverizer
②
①
Incoming Coal

Figure IX-3 Schematic of the Coal, Air and Ash Systems of a Power Plant With Proposed Sampling Points

Table IX-19

Semi-quantitative Analysis

Aluminum
Antimony
Arsenic
Barium
Beryllium
Bismith
Boron
Cadmium
Calcium
Cerium
Chlorine
Chromium
Cobalt
Copper
Fluorine
Gallium
Germanium
Iron
Lanthanum
Lead
Lithium
Manganese
Magnesium
Mercury
Molybdenum
Nickel
Osmium
Palladium
Phosphorus
Platinum
Potassium
Radium
Rhenium
Rhodium
Rubidium
Ruthenium
Scandium
Selenium
Silicon
Silver
Sodium
Strontium
Sulfur
Tin
Titanium
Thallium
Thorium
Uranium
Vanadium
Ytterbium
Yttrium
Zinc
Zirconium

Table IX-20

Quantitative Analysis

- Aluminum
- Antimony
- Arsenic
- Barium
- Beryllium
- Boron
- Cadmium
- Calcium
- Chlorine
- Chromium
- Cobalt
- Copper
- Fluorine
- Iron
- Lead
- Manganese
- Magnesium
- Mercury
- Molybdenum
- Nickel
- Selenium
- Silicon
- Silver
- Sulfur
- Uranium
- Vanadium
- Zinc

Table IX-21

1000 MW Coal Fired Power Plant
Trace Element Emissions (1)
NGP Coal

	# pounds/hour emitted
Boron	15.25
Barium	52.50
Beryllium	0.05
Cobalt	0.21
Chromium	0.53
Copper	2.10
Gallium	0.21
Germanium	0.11
Lanthanum	0.63
Lead	0.53
Manganese	10.50
Molybdenum	0.16
Nickel	0.74
Scandium	0.11
Strontium	21.00
Tin	0.11
Titanium	26.25
Vanadium	1.05
Yttrium	0.74
Ytterbium	0.05
Zinc	1.05
Zirconium	1.58

(1) Assumptions

- a) 10% ash in coal
- b) ash split is 80% fly ash and 20% bottom ash
- c) all trace element goes to fly ash
- d) same power plant characteristics as shown in Table IV-9
- e) compliance with NSPS particulate regulation (for this plant, 1050 # particulate emitted/hour)
- f) trace element coal concentrations equal to those given in Table IX-4

Table IX-22

250 MM SCFD Coal Gasification Plant
Trace Element Emissions (1)
NGP Coal

	# pounds/hour emitted
Boron	7.20
Barium	24.00
Beryllium	0.02
Cobalt	0.10
Chromium	0.24
Copper	0.96
Gallium	0.10
Germanium	0.05
Lanthanium	0.29
Lead	0.24
Manganese	4.80
Molybdenum	0.07
Nickel	0.34
Scandium	0.05
Strontium	9.60
Tin	0.05
Titanium	12.00
Vanadium	0.48
Yttrium	0.34
Ytterbium	0.02
Zinc	0.48
Zirconium	0.72

(1) Assumptions

a) Same as for Table IX-24 with exception of (e)

b) Same as for Table IV-10

c) 480 pounds particulate/hour total emissions from gasification complex, which includes 325 MW power plant

Table IX-23

250 MM SCFD Coal Gasification Plant Trace Element Emissions (22) Eastern Coal

	# pounds/hour emitted
Arsenic	0.31
Bromine	0.33
Cadmium	0.02
Chromium	0.38
Cobalt	0.13
Copper	0.33
Fluorine	2.22
Gallium	0.08
Lead	0.22
Manganese	1.20
Mercury	0.004
Nickel	0.33
Selenium	0.05
Vanadium	0.56

(22) Potential pollutants in coal and the environmental impact of coal gasification; Rhodes; March, 1973

SECTION X

RESEARCH NEEDS

10.1 SCOPE

The first year of study of coal activity in the Northern Great Plains states via the NGPRP probably raised more questions than answers. These questions have identified certain research needs which should be addressed in order for state and local planning agencies to make knowledgeable decisions regarding the environmental impact of coal mining and conversion activities. The activities of this work group during the next two years may serve to partially address some of the questions that have arisen. The general categories listed below define those areas requiring further work.

1. Meteorological data
2. Air quality data
3. Mining impacts upon air quality
4. Regional air quality estimation methodology
5. Trace element emissions
6. Energy conversion technology
7. Visibility impact
8. Long term health and welfare effects

Obviously answers to some of the above items cannot be obtained in a year or two, but a start can be made to identify the methodology for obtaining the requisite information.

10.2 FUTURE WORK GROUP ACTIVITIES

Activities planned by the work group for FY 75 and FY 76 are shown below. Work group meetings to discuss progress of the program will be held quarterly or as deemed necessary.

1. The work group will continue in FY 75 to take the lead in coordinating all air-related activities in the study area.

2. We will continue the collection and analyses of the samples obtained from the NGP ambient air monitoring network through FY 76.

3. We will continue the collection and reduction of meteorological data obtained at all meteorological stations through FY 76.

4. We will continue to compile data and information that will be used in writing the NGPRP final report and the special reports that this work group has identified as being appropriate. These special reports will discuss items such as control technology, coal gasification, trace element mass balances, and effects upon visibility.

5. The disturbance of land as a result of mining and related activities will cause an increase in the emissions of fugitive dust. In order to assess impact of these emissions on air quality, a study on a specific area will be designed. The background level should be assessed in an area prior to the start of a mining operation.

An air monitoring network will be designed using hi-volume samples to assess particulate concentrations in the immediate vicinity of a mining operation and at several sites at varying distances from the operation.

6. The work group will expand upon its trace element sampling program which was funded in FY 74. An intensive study will be planned to source sample a coal fired power plant in FY 75. Guidance from the FY 74 trace element sampling program will be utilized in order to narrow down the list of elements to be studied. An attendant intensive ambient monitoring program will be provided at the same time as the source sampling effort. This dual sampling effort should provide data with which to assess the adequacy of present diffusion models to predict trace element concentrations.

7. There is a need to identify the type and quantity of trace element emissions from coal gasification plants so that we may predict the atmospheric loadings and effects resulting from these plants. Bench scale and pilot plant studies are being performed on a couple of processes in this country, but there is no work published on commercial plants, since the U.S. does not have any commercial sized plants. There is a need to study the European and/or African gasification plants. Research funds may be funneled through AGA or other avenues to perform source sampling programs on those plants. The NERC-RTP via CSL may be the vehicle for promoting these studies because of their substantial budget.

Also, a literature survey of the type of data available regarding these gasification plants will be performed.

8. A concern exists over the concentrations of trace elements in the respirable size range of particulate matter. An intensive sampling program will be performed on a single coal-fired plant to provide insight to this concern. This work may

be performed in conjunction with item #6. This type of work would complement the work that has been performed by the NERC-RTP upon an Eastern coal fired power plant.

The AEC (Livermore Lab) is interested in participating in this type of program. It is conceivable that an interagency agreement could be entered into in order to conduct an extensive program.

9. A coordinated study will be conducted in the vicinity of a major coal fired power generating plant to assess the impact of emissions. The study will include an air quality monitoring network, a mass chemical analyses, and an evaluation of the concentrations in soils, plants and animals. This work may be performed in conjunction with item #'s 6 and 8.

The air quality monitoring network will sample the particulate and certain gaseous concentrations. Gases considered will include the criteria pollutants and other gases of general concern. The filters used to collect particulates will also be used to assess certain trace elements.

The concentration of trace elements in the soil, plants and animals will be correlated with the emissions coming from the plants. It is recommended that a cooperative arrangement be made with the State Game Commission for the animal studies. The study dealing with soils and plants could be coordinated with EPA research laboratories. Special attention will be given to the effect of sulfur oxide emissions on young plants, especially on land areas in the process of being reclaimed.

10. Little or no firm knowledge exists regarding the quantity of criteria pollutant emissions from gasification plants. Also, of significant interest are the magnitude and type of reduced sulfur compound emissions from these plants. The NERC-RTP is working on the development of emissions estimates and NSPS for gasification plants at the present time. It would be helpful for them to have actual emissions data from the commercial plants overseas.

Adequacy and extent of control technology is unknown for the present viable gasification processes. The work group will perform a literature search after consulting with RTP in an attempt to provide data on this topic.

11. The work group will expand upon its present diffusion modeling efforts. The availability of a model to predict regional air quality and long distance transport of pollutants is desirable. A case by case investigation of single emission sources will overlook the cumulative and interactive impacts of

many sources within a region. Consequently, we will adapt an existing regional transport and diffusion model for use in the Northern Great Plains Region. This model will:

a. Be capable of being understood by decision-makers without technical expertise.

b. Have been tested with some verification data available.

c. Use readily available air quality and meteorological data.

d. Provide output which can be easily compared to air quality standards.

An additional longer term need is for the development of new, more refined regional air quality models which remove some of the simplifying assumptions of existing models. Some site specific verification is required.

12. The need for the development of methodologies to assess visibility and other impacts of increased sub-micron particulate loadings upon the atmosphere is apparent.

All available existing visibility data in the Northern Great Plains Region will be compiled. Airports and local observers are two possible sources.

Within the next year, an attempt at formulating a visibility assessment methodology will be made. Furthermore, the methodology will be tested at least at one site in the Northern Great Plains, for example Colstrip or Gillette. Data collection should occur before and after large power plants begin operation to assess the effects that increased particulate emissions have on visibility. Sampling ambient air for particulate particle size will accompany in-field visibility assessment.

13. The large-scale development of fuel conversion facilities in the Northern Great Plains will result in a significant increase of emissions. Substantial HC and NO_x emissions will occur. This situation plus the high frequency of sunlight in the NGP provides the excellent potential for photochemical oxidant formation. Also, it is suggested that presently the hydrocarbon and possibly the oxidant air quality standards are being exceeded in many non-urban locations. In order to assess the impact of the proposed development, this work group will locate some HC and oxidant air quality monitors in the region. This effort may be a part of the present NGP monitoring network and tied into the present contractual arrangement.

14. A requirement for wide-scale flue gas desulfurization (FGD) development is not anticipated in Region VIII unless State regulations became more stringent than the NSPS (such as Colorado's), or if resolutions to significant deterioration mandate additional control. The amount of material to be disposed of is not as critical as the nature of the material. Collected flyash volume would not be much greater than the anticipated SO_3 or SO_4 sludge, but the chemical nature of the sludge could present a potential water problem.

Also, the capture and ultimate disposal of sludges containing possible significant quantities of trace elements heretofore uncollected may require careful handling.

Utilization of sludge is being studied by NERC-RTP and others and should be followed and promoted.

15. The quantity of emissions coming from an energy resource development area would indicate that health assessments should be scheduled both before and after the facility is operational.

A potential site would be the Crow or Northern Cheyenne Reservation in Montana. A number of samplers will be installed on the reservation and allowed to operate for several years as development takes place. This will allow for documenting impacts on air quality and human health over time as mines, power plants and gasification facilities become operational. The Indian Health Service could cooperate with health related aspects of study.

A second potential study would be a CHESS type study in an intensive development area such as Stanton. Since development is just starting, the study could acquire baseline information, if started immediately, and then track related health effects, if any, as development proceeds.

This would be a long-term study running perhaps 10 years.

16. The interplay of the Northern Great Plains Resources Program and recently promulgated federal and state regulations will be studied in detail. In view of recent promulgation of air regulations, indirect source regulations, 10-year maintenance plans and the soon to be promulgated significant deterioration regulations, the problem of energy resource development compatibility with such regulations should be evaluated in a systematic way. This will require an assessment of air sheds in the area, establishing air quality zones, and redesigning, if necessary, an air quality monitoring network to ascertain if the standards are achieved.

The compatibility of the energy resource development scenarios from the NGPRP to pertinent standards will be evaluated by employing point source and regional diffusion models. This effort could provide considerable information to the States in terms of siting guidance.

17. Effects upon health, vegetation, and visibility by SO_4 are not well understood. It is theorized that some concentrations may prove to be harmful. Due to the increased fuel conversion facility development in the NGP, an increase in particulate matter and SO_2 will result. Thus, we have the makings for sulfate production. Measurement of the SO_4 concentrations on all hi-vol filters in the NGP monitoring network would provide the data necessary to make some comments upon the trent of SO_4 levels in the atmosphere. Also, it will provide an important function by comparing the data to existing State standards. A long-term study is required (at least 10 years) in order to make meaningful conclusions.

18. Effects upon health, vegetation and visibility due to concentrations of nitrates and fluorides are not well understood. Nitrate and fluoride emissions in the Northern Great Plains will undoubtedly increase with the addition of new power and gasification plants. Therefore, it will be necessary to analyze the NGPRP high-volume sampler filters for nitrate and fluoride concentrations as well as sulfate and trace elements. Trend analysis is desirable and requires long-term sampling (at least ten years) in order to draw valid conclusions.

19. The task group will investigate the effect of an increase in cloud condensation nuclei upon the amount of rainfall. Several research studies have produced statistical support of both positive and negative effects of anthropogenic aerosols (e.g. from power plants) on precipitation. The difference in the conditions constituting a positive effect as compared to a negative effect have not been conclusively determined. Many new power plants and gasification plants planned for the Northern Great Plains area will produce considerable air emissions, some of which will become cloud condensation nuclei. The effect of the addition of significant quantities of these nuclei on precipitation in this region will be investigated.

20. Scientific theories have been advanced which predict profound effects upon the weather and climatological status of the earth. It is theorized on one hand that if CO_2 levels continue to increase as a result of combustion of fossil fuels, an increased trapping of infrared radiation will occur. This would result in a gradual heating effect and eventually cause the "greenhouse" effect. Increased CO_2 levels have been noted at the Mauna Loa observatory in Hawaii. On the other hand, it has been suggested that if the atmosphere is subjected to increased

particulate loadings, the amount of solar radiation reaching the ground will be reduced. This would result in an "ice age" effect.

A long-term monitoring program would be necessary in order to provide data for these two theories. At least 15 years of data would be needed to make any meaningful conclusions. CO_2 measurements should be made as a part of the NGP monitoring network in order to provide one or two data points for this trend analysis.

21. In order to verify the effects of increased atmospheric SO_2 loadings upon the pH of rainfall, extensive rain data and analyses would need to be performed. The key factors determining the pH of rain should first be identified. The chemistry should be discussed. This work group will provide substantial input to this research project. Also, a literature search regarding this subject especially looking at University thesis will provide some initial data.

Collection of rainwater along with routine analyses could be performed in conjunction with the NGP monitoring network.

22. EPA was recently directed to require states to address the question of the maintenance of air quality in the period beyond the original attainment dates specified in the State Implementation Plans (1975-77). To accomplish this, the states in Region VIII are designating areas which either currently exceed the standards or which have the potential to exceed the standards by 1985. In the coming year the state agencies, with EPA assistance, will be doing in-depth analyses of these areas for the purpose of developing a "Maintenance Plan" for each designated area. Because the NGP states contain large untapped sources of energy in the form of coal and oil shale, the EPA Regional Office has encouraged the states to designate areas containing deposits of either as Air Quality Maintenance Areas (AQMA's). Maintenance plans will be developed for these areas by June 18, 1975.

The information already generated by the NGPRP has been extensively used in the designation process; however, the level of sophistication of the analysis to be conducted in the next year will be much higher. Outputs from the NGPRP will be vital as inputs to the maintenance planning process for plans developed either by the states or by EPA.

APPENDIX

TABLE A-1 AIR QUALITY DATA AND DISCUSSION OF SELECTED AIR QUALITY SAMPLING AND ANALYSIS METHODS

FIGURE A-1 SEASONAL WIND ROSES

through

FIGURE A-4

FIGURE A-5 SEASONAL TEMPERATURE DATA

through

FIGURE A-8

FIGURE A-9 SEASONAL PRECIPITATION DATA

through

FIGURE A-12

TABLE A-1

AIR QUALITY DATA RECORDED IN THE NORTHERN GREAT PLAINS RESOURCE PROGRAM STUDY AREA

The following charts have been compiled from computer printouts from the National Aerometric Data Bank. This Bank records data from the National Air Surveillance Network stations and contributing independent state and local sampling networks. For more information contact the Air and Water Programs Division, Region VIII, Environmental Protection Agency, 1860 Lincoln, Denver, Colorado 80203; or the Monitoring and Data Analysis Division, Office of Air Programs, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Note that all means, and standard deviations are ARITHMETIC with the sole exception of total suspended particulates which have GEOMETRIC means and standard deviations.

Sample collection and analysis methods are listed below. Column 4 uses the following numbers to indicate method: (units are micrograms per cubic meter, ug/m^3 unless otherwise specified.)

CODE

1. Hi-Vol/gravimetric (24 hr. sample)
2. Hi-Vol/turbidimetric (24 hr. sample)
3. Hi-Vol/specific ion electrode (24 hr. sample)
4. Hi-Vol/proportional counter (24 hr. sample) (picocuries/cu. meter)
5. Hi-Vol/colorimetric (24 hr. sample)
6. Hi-Vol/reduction diazo coupling (24 hr. sample)
7. Hi-Vol/emission spectra
8. Hi-Vol/Willard Winter/specific ion (24 hr. sample)
9. Hi-Vol/benzene extraction - SO_xHLET (24 hr. sample)
10. Hi-Vol/emission spectra - muffle furnace (24 hr. sample)
11. Hi-Vol/emission spectra - low temp ash (24 hr. sample)
12. Hi-Vol/2-4 xylenol (24 hr. sample)
13. Hi-Vol/sodium phenolate (24 hr. sample)
14. Gas Bubbler/Jacobs-Hoshheiser (100 ml tube & frit) (24 hr. sample)
15. Gas Bubbler/West Gaeke sulfamic acid (24 hr. sample)
16. Gas Bubbler/sodium phenolate (24 hr. sample)
17. Tape sampler/transmittance (2 hr. sample) CoHS/1000 linear ft.
18. Hi-Vol/Nessler (24 hr. sample)
19. Lead candle/gravimetric (1 month sample, mg SO_3/100 sq. cm/day)

Primary and secondary standards refer to the National Ambient Air Quality Standards created by the Clean Air Act of 1970.

SELECTED AIR QUALITY SAMPLING AND ANALYSIS METHODS

1. High-Volume Sampler

The high-volume (hi-vol) sampler is a device that draws a large volume of air across a filter. Analysis of the soiled filter can determine concentrations of

a. total suspended particulate matter

b. trace metals (e.g., beryllium, cadmium, etc.)

c. ions (ammonium, sulfate, nitrate, fluoride)

d. benzene soluble organic compounds.

A brief description of the laboratory methods involved in the determination of these concentrations follows:

a. Total Suspended Particulates

The hi-vol samplers, operating at approximately 1.5 cubic meters per minute, collect particulate matter from about 2200 cubic meters of air during the normal 24 hour sampling period. The filters used are 8" by 10" fiberglass filters selected for low and uniform background concentrations of those substances to be measured. Weighing the filters before and after they are used determines the mass of the particulate matter in the 2200 cubic meters of air. This particulate mass and air volume allow for the calculation of the concentration of particulate matter, expressed usually in micrograms per cubic meter.

b. Trace Metals

i. Emission Spectrometry

In the metals analysis, a portion of the soiled filter is ashed to burn off organic material and then treated with a mixture of hydrochloric and nitric acids to extract the metals. The manner of ashing the sample is critical in the determination of the more volatile metals such as lead, zinc and cadmium. At one time, samples were ashed in a muffle furnace at 500°C, but they are now ashed in a low temperature oxygen plasma furnace at about 150°C. The sample is then optically excited in an optical emission spectrograph which measures the intensity of the emission lines of each metal. These emission lines are characteristic of and different for each metal. In a sense, these lines are a particular metal's "signature." The measurements are then compared to calibration curves of metals of known concentrations to complete the analysis.

NASN filters are routinely analyzed for beryllium, cadmium, chromium, cobalt, copper, iron, lead, manganese, nickel, tin, titanium, and vanadium.

ii. Spark Source Mass Spectrometry

Spark source mass spectrometry (SSMS) is capable of determining trace elements down to the low parts per billion range. Ions representative of the material under analysis are produced by applying a pulsed radio frequency potential of 30 Kev to a pair of electrodes mounted in the instrument source. The ions produced are accelerated into the analyzer systems of the mass spectrometer by application of a 20 Kev accelerating potential. These ions are of different mass-to-charge ratios, hence, they describe different radial paths in the magnetic field and consequently come into focus at different points along a photographic plate. Alternatively, the ion species are scanned across a collector slit placed at the principal focus and determined electrically. The SSMS technique enjoys 1) high sensitivity, 2) total element coverage and 3) ease of detection via the linear response characteristic of the analyzer.

c. Ions (ammonium, sulfate, nitrate and fluoride)

Ammonium, sulfate and nitrate ions are analyzed by first preparing an aqueous extract of the particulate sample. This extract is then reacted with different chemical reagents to produce colored solutions characteristic of each of the ions. A spectrophotometer measures the color intensity of each solution which can then be compared to the color intensities of solutions of known ion strength to determine the concentrations.

Fluoride ion concentrations are measured by studying the electrical conductivity of fluoride ions in aqueous solution. The analysis is conducted on a sample of the same water extract prepared for the analysis of the above three ions. A sodium citrate-carbonate solution is added to control the interference of the metal ions. A fluoride-selective electrode placed in this solution generates an electric voltage in proportion to the fluoride ion concentration. The fluoride ion concentration is then obtained by comparing this potential to that obtained underthe same conditions from standard solutions of known fluoride content.

d. Benzene Soluble Organics

The numerous specific organic compounds that dissolve in benzene are believed to include most of the man made organic pollutants. Natural organic airborne particles, such as pollens and molds, are not benzene soluble.

Benzene soluble organics are extracted from the particulate sample with benzene in a soxhlet extractor. After extraction the solution is concentrated and the benzene allowed to evaporate. The remaining organic matter is weighed to determine the concentration.

2. Gases

Gas samples are often gathered with a bubbler sampler. Air is drawn through a tube and allowed to bubble into a vessel containing the appropriate absorbing reagent. Following sample collection (usually for a 24 hour period) the bubbler tubes are sent back to a laboratory for analysis. The analytic method used for sulfur dioxide is that of West and Gaeke. Nitrogen oxide measurements are based on the procedures of Jacobs and Hockheiser. Both methods are similar in that the bubbled gases react with the specific SO_2 and NO_x absorbing reagents producing special colored solutions. Intensities of these colored solutions can be measured (color-metrically) and compared to standard solutions of known gas concentrations.

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m^3		QUARTERLY MEANS ug/m^3				ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
MONTANA																
Big Horn County (Ranch)	Total suspended particulates	1973	1	27	2	44	6	18	--	--	--	--	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	0
Billings (Industrial)		1972	1	65	21	247	--	--	--	--	73	1.70			0	0
(Industrial)		1973	1	37	7	135	32	47	41	--	--	--				
		1972	1	34	18	82	36	--	--	39	--	--			0	3
(Rural)		1973	1	41	11	170	51	56	47	--	52	1.72			0	1
		1972	1	32	6	131	39	--	--	37						
		1971	1	23	16	138	--	--	--	43	--	1.67			0	0
(Center City)		1973	1	38	17	203	90	58	86	--	75	1.81			0	2
		1972	1	33	25	224	66	--	--	91	--	--			0	5
		1971	1	19	52	147	--	--	--	75	--	1.51			0	0
(Commercial)		1973	1	30	18	111	57	58	60	--	58	1.50			0	0
		1972	1	28	18	279	69	--	--	55	61	2.02			1	2
		1971	1	13	33	151	--	--	--	77	--	1.67			0	1

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	2	3	4	ANNUAL MEAN ug/m3	STANDARD DEVIATION ug/m^3	STANDARDS PRIMARY ug/m^3	STANDARDS SECONDARY ug/m^3	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	# OBSERVATIONS GREATER THAN STANDARDS SECONDARY
Forsyth		1973	1	34	3	138	9	39	61	--	24	2.82			0	0
		1972	1	36	17	111	--	18	25	11	17	2.44			0	0
Hardin		1973	1	29	21	255	82	114	139	--	107	2.00			0	3
		1972	1	37	27	147	--	61	53	65	59	1.62			0	0
Laurel		1973	1	24	18	97	41	57	41	--	45	1.54			0	0
		1972	1	32	20	77	35	31	--	29	77	1.51				
		1971	1	8	26	96	--	--	--	49	--	1.65				
Miles City		1973	1	63	7	380	47	67	158	--	73	2.80			5	18
		1972	1	110	--	--	39	119	91	26	53	2.83			9	19
Powder River County (Rural)		1973	1	13	2	55	14	--	--	--	14	2.59			0	0
		1972	1	26	14	150	--	41	30	44	39	1.95			0	0
Rosebud County (Ranch)		1973	1	38	3	73	7	18	29	--	14	2.33			0	0
		1972	1	10	2	10	--	--	--	6		1.68			0	0

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m^3		QUARTERLY MEANS ug/m^3				ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
Rosebud County (Ranch)		1973	1	55	10	126	--	--	46	27	--	--			0	0
		1972	1	15	14	180	31	54	--	--	--	--			0	2
Sidney		1973	1	75	6	171	21	27	47	--	30	2.01			0	1
NEBRASKA																
Chadron		1973	1	27	19	297					73					
		1972	1	27	15	170	68	67	47	61	62	1.80			0	1
Lincoln County (Rural)		1973	1	18	[illegible]	76					21				0	0
North Platte		1973	1	29	13	137					53				0	0

SITE	POLLUTANT	YEAR	SAMPLING ANALYZING METHOD	SAMPLES	EXTREMES MIN OBS ug/m^3	MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3				ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3		# OBSERVATIONS GREATER THAN STANDARDS	
							1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
North Platte	Total suspended particulates	1972	1	29	2	107	28	43	52	53	43	2.26	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	0
Scottsbluff		1973	1	28	18	178						71			0	2
Scottsbluff		1972	1	22	41	289	83	60	81	158	72	2.07			1	3
Valentine		1972	1	2	47	57				51	51	1.14			0	0
NORTH DAKOTA		Jan-Mar 1973	1	14	42	105	64.4					1.3 (1st qu)				
Bismarck	Total suspended particulates	1972	1	30	24	213	67	105	97	79	87	1.71	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	4
			1	58	17	406	51	68	63	57	59	1.71			1	1
		1971	1	26	27	136	53	83	73	91	73	1.59			1	1
		Jan-Sept	1	20	29	104	48	56	54	--	52	1.40			0	0
		1970	1	26	17	211	58	95	71	109	79	1.99			1	6
			1	25	17	165	58	95	61	68	69	1.92			[illegible]	3
		1969	1	25	20	243	49	114	79	66	70	1.80			0	2
		1968	1	26	27	256	59	113	62	62	70	1.80			0	3
		1967	1	25	24	216					66	1.88				
	Sulfate ion	1973 Jan Mar	2	14	2.3	7.1	7.82									
		1972 Jan-Mar	2	11	[illegible]	[illegible]	5.2									

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	2	3	4	ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3 PRIMARY	STANDARDS ug/m^3 SECONDARY	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	# OBSERVATIONS GREATER THAN STANDARDS SECONDARY
Bismarck	Sulfate ion	1970	5	26	2.8	8.0	6.7	4.9	3.9	5.7	5.3	1.5	365 (24 hr) 80(ann)			
		1969	5	23	.3	12.3	6.7	4.1	3.2	.8	3.8	3.4				
		1968	5	26	.3	7.3	2.8	2.2	4.0	3.2	3.1	1.6				
		1964	5	25	1.0	6.4	4.0	3.7	2.4	1.8	3.0	1.3				
		1963	5	26	2.0	7.8	4.5	3.2	3.4	4.7	3.9	1.4				
		1962	5	25	1.5	8.0	4.8	3.6	3.0	2.5	3.5	1.9				
		1961	5	25	1.3	9.0	2.4	3.2	3.7	4.9	3.6	1.7				
		1960	5	26	.5	6.1	2.9	.8	1.0	2.7	1.8	1.4				
		1959	5	25	.3	7.4	2.6	1.6	1.1	1.7	1.7	1.4				
		1958	2	26	2.8	15.1	5.8	5.8	4.7	6.8	5.8	3.4				
		1957	2	23	1.8	14.2	4.9	5.0	4.3	5.3	4.9	2.7				
	Nitrate ion	Jan-Mar 1973	3	14	.59	6.89	1.79									
		1972	3	15	.41	3.59	1.54						100(ann)	100(ann)		
		1970	6	26	.30	3.00	1.43	1.2	.77	.57	1.00	.65				
		1969	6	25	.20	5.30	1.1	1.84	.59	1.48	1.20	1.22				
		1968	6	26	.20	2.2	.66	.88	.41	.93	.71	.46				
		1964	6	26	.10	1.1	.43	.63	.60	.50	.54	.28				
		1963	6	26	.10	1.2	.41	.45	.60	.60	.52	.27				
		1962	6	25	.10	2.1	.95	1.00	.40	.35	.66	.47				
		1961	6	25	.10	1.5	.94	1.03	.80	.45	.81	.36				
		1960	6	26	.20	2.9	1.07	.54	.86	.72	.79	.61				
		1959	6	25	.10	1.7	.66	.74	.46	.43	.57	.35				
		1958	12	26	.20	1.9	1.06	1.07	.73	.68	.90	.43				
		1957	12	23	.50	1.7	.92	1.12	1.07	1.23	1.09	.32				

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m^3		QUARTERLY MEANS ug/m^3				ANNUAL MEAN un/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
Minot	Nitrate ion	1972 Jan-Mar	3	7	.4	1.8	1.07	--	--	--						
	Fluoride ion	1972	8	30	.02	.11	.04	.02	.02	.04						
	Beta (gross)	1972	4	27	.02	.36	.10	.19	.17	.08						
Mandan	Total suspended particulates	1972	1	27	15	112	33	49	47	38	42	1.66	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	0
		1970 Oct-Dec	1	6	11	83	--	--	--	42	42	2.02				
	Sulfate ion	1972 Jan-Mar	2	6	4.0	9.2	6.9									
	Nitrate ion	1972 Jan-Mar	3	6	.88	4.34	2.33									
	Fluoride ion	1972	8	22	.02	.04	.02	.02	.02	--	.02					
	Beta (gross)	1972	4	22	.05	.99	.14	.41	.12	--						
Ward County	Total suspended particulates	1973 Jan-Mar	1	14	16	508	63.11	--	--	--		2.81 (1st qu)				
near Lake Darling (background)		1972	1	52	3	63	12	28	24	18	19	1.89			0	0
		1970	1	25	3	49	16	23	25	15	19	2.11			0	0
		1969	1	21	5	52	15	18	28	120	20	1.80			0	0
		1968	1	26	6	69	22	25	22	13	20	1.94			0	0
		1967	1	26	6	75					28	1.92			0	0
	Fluoride ion	1973 Jan-Mar	8	14	.02	.05	.03									

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m3		QUARTERLY MEANS ug/m3				ANNUAL MEAN ug/m3	STANDARD DEVIATION ug/m3	STANDARDS ug/m3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
Bismarck	Beryllium	1969	11				0	0	0	0	-----					
		1968	11	25	0	0	25 samples below minimum detectable concentration									
	Bismuth	1958	10	25	.000	.000	.000	.000	.000	.000	.000	.000				
	Cadmium	1969	11				0	0	0	0	-----					
		1968	11	25	0	0	25 samples below minimum detectable concentration									
		1958	10	25	.001	.001	.001	.001	.001	.001	.001	.000				
	Chromium	1969	11				0	0	0	0	-----					
		1968	11	25	0	.041	19 samples below minimum detectable concentration									
		1958	10	25	.003	.032	.008	.013	.018	.025	.015	.009				
	Cobalt	1969	11				0	0	0	0	-----					
		1968	11	25	0	0	25 samples below minimum detectable concentration									
		1958	10	25	.002	.002	.002	.002	.002	.002	.002	.000				
	Copper	1969	11				.04	.02	.09	.07	.05					
		1968	11	25	.00	.16	.07	.04	.03	.03	.04	.04				
		1958	10	25	.00	.31	.05	.05	.02	.07	.05	.06				
	Iron	1969	11				.6	1.9	1.5	1.5	1.4					
		1968	11	25	.3	5.6	1.4	2.8	1.3	1.4	1.7	1.24				
		1958	10	25	.4	10.0	.24	.20	.10	.10	.17	.16				
	Lead	1969	11				.83	.70	.59	1.30	.85					
		1968	11	25	.24	2.00	.77	.41	.38	.93	.61	.40				
		1958	10	25	.00	.60	.24	.20	.10	.10	.17	.16				
	Manganese	1969	11				.01	.05	.04	.04						
		1968	11	25	.00		17 samples below minimum detectable concentration									
		1958	10	25	.00	.13	.02	.06	.05	.05	.05	.03				
	Molybdenum	1958	10	25	.001	.010	.004	.001	.005	.006	.004	.004				

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m3 MIN OBS	MAX OBS	QUARTERLY MEANS ug/m3 1	2	3	4	ANNUAL MEAN ug/m3	STANDARD DEVIATION ug/m3	STANDARDS ug/m3 PRIMARY	SECONDARY	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	SECONDARY
Bismarck	Nickel	1969	11				0	0	0	0	-----					
		1968	11	25	.002	.010	.009	.007	.006	.005	.006	.002				
		1958	10	25	.002	.050	.022	.026	.013	.012	.019	.013				
	Tin	1969	11				0	0	0	0	-----					
		1968	11	25	0	0	25 samples below minimum detectable concentration									
		1958	10	25	.00	.030	.009	.007	.006	.005	.011	.011				
	Titanium	1969	11				0	0	0	0	-----					
		1968	11	25	.00	.10	24 samples below minimum detectable concentration									
		1958	10	25	.01	.14	.02	.06	.03	.03	.04	.04				
	Samarium	1968	11	25	.02	.04	.02	.02	.02	.02	.02	.00				
	Vanadium	1969	11				0	0	.012	0	-----					
		1968	11	25	0	0	25 samples below minimum detectable concentration									
		1958	10	25	.001	.006	.003	.003	.001	.001	.002	.002				
	Zinc	1968	10	25	.0	.5	.1	.0	.0	.0	.1	.1				
	Strontium	1968	11	25	.1	.1	.1	.1	.1	.1	.1	.0				
	Yttrium	1968	11	25	.000	.001	.000	.001	.000	.000	.001	.000				
	Ammonium ion	1970	13	26	.02	.10	.02	.05	.02	.06	.03	.04				
		1969	13	24	.02	2.0	.56	.05	.10	.04	.21	.47				
		1968	13	26	.02	.20	.10	.09	.04	.06	.07	.05				
		1964	13	26	.02	.02	.02	.02	.02	.02	.02	.00				
		1963	13	26	.02	.10	.05	.02	.04	.04	.04	.03				
		1962	13	25	.02	.10	.02	.04	.02	.02	.03	.01				
		1961	13	25	.02	.10	.02	.04	.02	.02	.03	.01				
		1960	13	26	.02	.02	.02	.02	.02	.02	.02	.00				
		1959	13	25	.02	.02	.02	.02	.02	.02	.03	.00				

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m3		QUARTERLY MEANS ug/m3				ANNUAL MEAN ug/m3	STANDARD DEVIATION ug/m3	STANDARDS ug/m3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
Bismarck	Fluoride ion	1973 Jan-Mar	8	14	.02	.02	.02									
		1972	8	58	.02	.20	.05	.03	.02	.04	.035					
		1970	8	26	.02	.09	.04	.04	.02	.02	.03	.02				
		1969	8	25	.02	.47	.28	.02	.02	.02	.10	.13				
		1968	8	26	.02	.21	.04	.02	.02	.06	.03	.04				
	Benzene soluble organic fraction	1970					3.7	2.3	2.3	4.1	3.1					
		1969					3.1	3.5	3.5	6.1	4.0					
		1963	9	26	.9	9.5	4.6	2.9	4.8	3.3	4.0	2.0				
		1962	9	25	1.4	20.3	5.5	6.6	4.2	3.6	4.9	3.9				
		1961	9	25	1.0	14.3	5.3	3.9	3.5	4.0	4.1	2.8				
		1960	9	27	.8	8.4	3.4	3.3	5.6	2.7	2.8	1.8				
		1959	9	25	1.6	6.9	3.5	3.4	3.2	4.2	3.6	1.4				
		1958	9	26	1.6	10.9	4.9	5.4	4.6	4.4	4.9	2.5				
		1957	9	24	1.7	9.0	3.9	3.0	3.3	5.3	3.9	1.8				
	Antimony	1958	10	25	.01	.01	.01	.01	.01	.01	.01	.00				
	Soiling index	1972	17	3,844	.00	2.70										
	Beta (gross)	1973	4	14	.05	.62	.33									
		1972	4	58	.02	1.45	.10	.34	.15	.05						
		1964	4	26	.20	6.10	1.46	2.83	.90	.38	1.38	1.34				
		1963	4	26	.80	17.6	7.57	10.07	5.86	1.45	6.27	4.22				
		1962	4	25	1.90	29.8	5.77	5.43	4.59	12.88	7.06	6.11				
		1961	4	25	.00	25.2	.02	.14	.99	15.8	4.11	7.75				
		1960	4	26	.00	.40	.08	.17	.13	.05	.11	.09				
		1959	4	25	.10	11.00	4.7	5.07	.74	.10	2.59	2.88				

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	QUARTERLY MEANS ug/m^3 2	QUARTERLY MEANS ug/m^3 3	QUARTERLY MEANS ug/m^3 4	ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3 PRIMARY	STANDARDS ug/m^3 SECONDARY	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	# OBSERVATIONS GREATER THAN STANDARDS SECONDARY
Bismarck	Beta (gross)	1958	4	26	.50	14.2	1.47	6.51	2.77	4.88	3.92	3.25				
Dickinson	Total suspended particulates	1973 Jan-Mar	1	8	48	94	70					1.28 (1st qu)				
		1972	1	28	3	105	25	58	50	41	42	2.12			0	0
		1970	1	25	8	126	27	55	68	41	46	2.01			0	0
	Sulfate ion	1973 Jan-Mar	2	8	2.2	24.3	5.9									
		1972 Jan-Mar	2	7	1.6	4.4	3.0									
	Nitrate ion	1973 Jan-Mar	3	8	.53	1.89	.99									
		1972 Jan-Mar	3	7	.37	1.51	.97									
	Fluoride ion	1973 Jan-Mar	8	8	.02	.13	.04									
		1972	8	28	.02	.07	.03	.02	.02	.02						
	Beta (gross)	1973	4	8	.04	.60	.31									
		1972	4	28	.02	.36	.07	.19	.12	.05						
	Sulfation rate	1970	17	12	.0	.4	.2	.1	.0	.0	.1	.1				
Minot	Total suspended particulates	1972	1	30	11	420	28	65	78	89	60	2.27			2	3
		1970	1	23	17	272	28	78	47	40	42	2.10			1	3
		1969	1	12	2	119	13	61	72	46	34	2.91			0	0
		1968	1	26	14	891	65	106	49	45	62	2.54			2	2
	Sulfate ion	1972 Jan-Mar	2	7	1.6	5.2	3.6	--	--	--						

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m^3		QUARTERLY MEANS ug/m^3				ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
Ward County	Beta (gross)	1973	4	14	.04	1.23	.54									
		1972	4	52	.00	.70	.09	.25	.13	.05						
		1964	4	25	.10	5.30	1.78	2.70	.79	.30	1.38	1.52				
		1963	4	24	.70	16.00	7.96	9.70	5.95	1.26	6.50	4.53				
		1962	4	24	2.20	20.10	6.08	5.12	3.79	8.82	5.74	3.60				
		1960	4	23	.00	.30	.10	.14	.08	.03	.08	.08				
		1959	4	25	.00	8.6	2.63	5.98	1.20	.05	2.16	2.62				
		1958	4	26	.20	22.00	1.53	7.94	1.41	6.02	4.09	5.36				
	Benzene soluble organic fraction	1962	9	24	.0	3.4	1.0	.9	1.7	1.0	1.2	.7				
		1961	9	25	.8	2.3	.8	1.1	1.2	1.3	1.1	.5				
		1960	9	23	.2	2.3	1.3	1.0	1.0	.8	1.0	.4				
		1959	9	25	.0	2.0	.9	.8	.9	1.2	1.0	.4				
		1958	9	26	.0	5.0	1.9	2.4	1.6	1.6	1.9	1.1				
	Sulfate ion	1973 Jan-Mar	2	14	2.3	13.5	6.2	--	--	--						
	Nitrate ion	1973 Jan-Mar	3	14	.29	7.25	2.53	--	--	--						
Williston	Total suspended particulates	1973 Jan-Mar	1	8	33	117	47	--	--	--		1.50 (1st qu)				
		1972	1	25	7	71	22	43	44	34		1.74			0	0
SOUTH DAKOTA																
Black Hills Nat'l Forest (background)	Total suspended particulates	1972	1	29	6	66	13	14	27	13	16	1.62	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	0
		1971	1	23	7	46	8	14	26	14	14	1.93			0	0
		1970	1	23	7	69	11	25	33	11	18	1.88			0	0

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	QUARTERLY MEANS ug/m^3 2	QUARTERLY MEANS ug/m^3 3	QUARTERLY MEANS ug/m^3 4	ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS PRIMARY ug/m^3	STANDARDS SECONDARY ug/m^3	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	# OBSERVATIONS GREATER THAN STANDARDS SECONDARY
Black Hills	Total suspended particulates	1969	1	26	3	34					11	1.93				
		1968	1	26	3	28	6	8	13	17	8	1.77				
		1967	1	25							23	2.12			0	0
	SO_2	1972	15	24	3	7	3	3	4	6	4	2	365 (24 hr) 80(ann)			
		1970	15	21	3	18	9	6	7	3	7	5			0	0
		1969	15	26							8	4			0	0
	NO_x	1972	14	25	8	132	45	35	43	26	38	26	100(ann)	100(ann)	--	--
		1971	14	21	22	160	37	37	66	36	45	25			--	--
		1970	14	22	22	108	31	59	37	50	42	29			--	--
	Beryllium	1969	11				0	0	0	0	--					
		1968	11	26			26 samples below minimum detectable concentration									
	Cadmium	1969	11				0	0	0	0	--					
		1968	11	26	0	.0007	25 samples below minimum detectable concentration									
	Chromium	1969	11				0	0	0	0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									
	Cobalt	1969					0	0	0	0	--					
		1968	11	26	0	.002	24 samples below minimum detectable concentration									
	Copper	1969	11				.250	.330	.510	.360	.362					
		1968	11	26	.055	.450	.165	.248	.311	.246	.233	.100				
	Iron	1969	11				0	0	0	0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									
	Lead	1969	11				.022	.017	.020	.031	.022					
		1968	11	26	0	.024	20 samples below minimum detectable concentration									
	Manganese	1969	11				0	0	0	0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	2	3	4	ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS PRIMARY ug/m^3	STANDARDS SECONDARY ug/m^3	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	SECONDARY
Black Hills	Nickel	1969	11				0	0	0	0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									
	Tin	1969	11				0	0	0	0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									
	Titanium	1969					0	0	0	0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									
	Samarium	1968	11	26	0	0	26 samples below minimum detectable concentration									
	Strontium	1968	11	26	.1	.1	.1	.1	.1	.1	.1	0				
	Vanadium	1969					.0	.0	.004	.0	--					
		1968	11	26	0	0	26 samples below minimum detectable concentration									
	Yttrium	1968	11	26	.0002	.0002	.0002	.0002	.0002	.0002	.0002	0.				
	Ammonium ion	1969	13	26	.02	.20	.09	.10	.10	.07	.09	.04				
		1968	13	25	.02	.10	.10	.09	.10	.10	.10	.01				
		1967	13	25	.02	.10	.04	.02	.07	.10	.06	.04				
		1966	13	25	.02	.20	.10	.10	.08	.12	.10	.03				
		1965	18	26	.02	1.50	.02	.02	.24	.02	.08	.29				
	Fluoride ion	1969	3	26	0.	.08	20 samples below minimum detectable concentration									
		1968	3	26	.02	.02	.02	.02	.02	.02	.02	0				
		1967	3	25	.02	.16	.03	.02	.05	.03	.03	.03				
	Nitrate ion	1969	6	26	.02	.90	.36	.22	.14	.10	.21	.19				
		1968	6	26	.02	.40	.14	.13	.9	.14	.12	.10				
		1967	6	25	.02	.70	.25	.36	.50	.25	.34	.16				
		1966	6	25	.10	.90	.14	.40	.44	.27	.31	.22				
		1965	12	26	.10	1.30	.23	.50	.24	.33	.32	.24				
	Sulfate ion	1969	5	26	.8	4.1	1.7	1.4	2.1	2.2	1.9	.7				

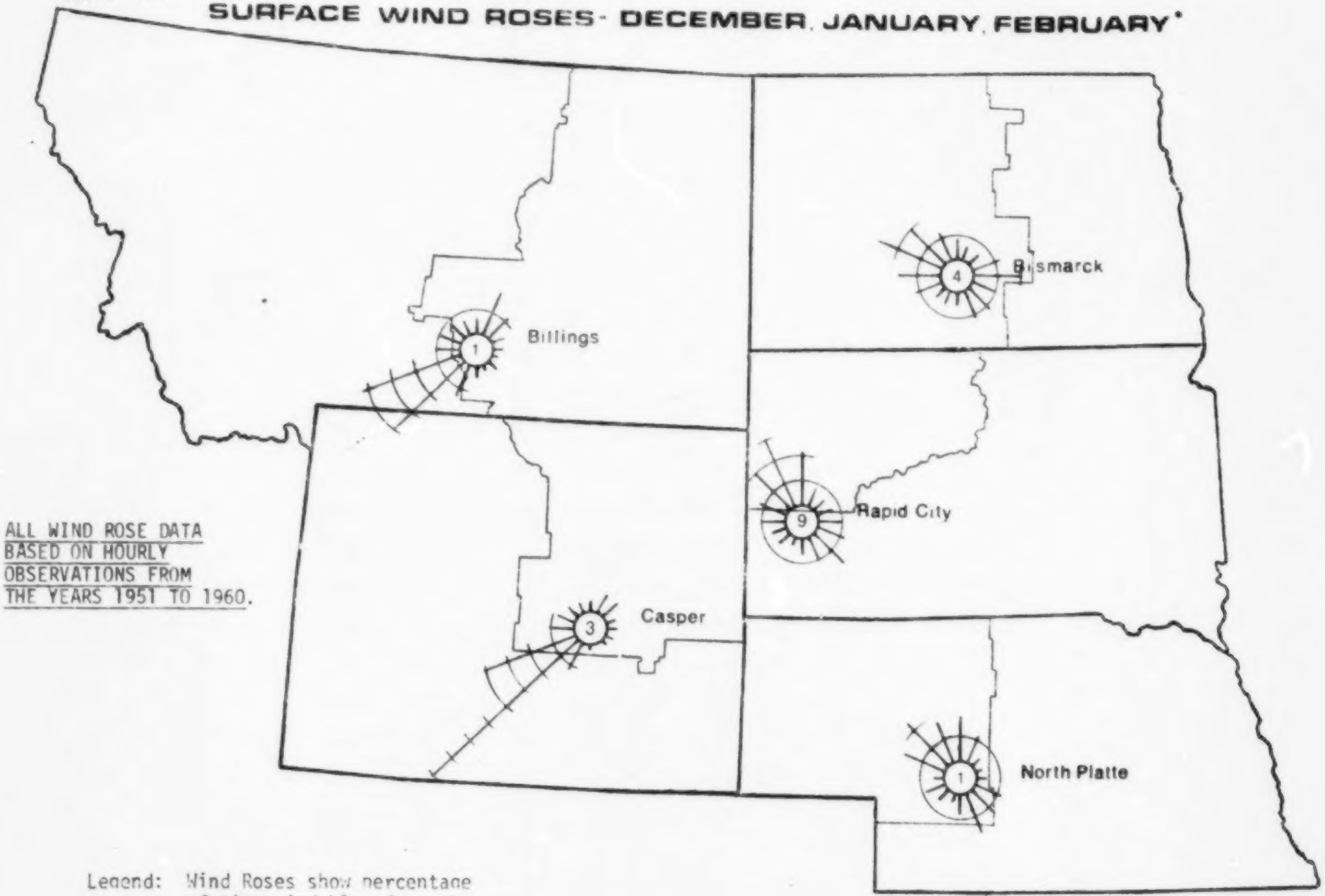
SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	2	3	4	ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS PRIMARY ug/m^3	STANDARDS SECONDARY ug/m^3	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	# OBSERVATIONS GREATER THAN STANDARDS SECONDARY
Black Hills	Sulfate ion	1968	5	26	.3	2.4	.9	1.0	.7	.9	.9	.4				
		1967	5	26	.3	2.8	1.3	.9	1.7	1.8	1.4	.7				
		1966	5	25	1.3	3.2	1.8	2.5	2.0	2.6	2.2	.5				
		1965	2	26	.8	4.1	1.7	1.4	2.1	2.2	1.9	.7				
	Beta (gross)	1966	4	25	.10	.60	.13	.34	.16	.12	.18	.14				
		1965	4	26	.00	.90	.36	.68	.13	.12	.32	.28				
		1964	4	26	.30	4.90	2.17	2.61	.97	1.42	1.79	1.33				
		1963	4	26	.90	25.1	13.01	11.48	6.72	1.83	8.20	6.57				
		1962	4	24	2.10	64.8	9.18	6.55	14.38	7.38	9.37	12.29				
		1958	4	21	11.00	37.4	2.67	10.52	7.48	16.62	9.00	8.57				
	Benzene soluble organic fraction	1969	9			.8	1.1	1.7	1.0	1.1						
		1962	9	24	0	8.7	.7	1.0	1.9	.6	2.8	2.1				
		1958	9	21	0	3.7	2.3	3.4	4.7	1.1	1.1	.8				
Rapid City County Health Dept.	Total suspended particulates	1973 Apr-July	1	14	35	149	--	59	--	--	59	1.52	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	0
		1973 Jan-Mar	1	14	38	377	125	--	--	--		2.28 (1st qu)				
		4/72-4/73	1	53	25	253	69	60	74	78	71	1.75			0	4
Water Treatment Plant	Total suspended particulates	1973 Apr-July	1	16	70	200	--	119			119	1.32			0	3
		1973 Jan-Mar	1	9	25	248	53	--	--	--		2.08 (1st qu)				
		4/72-4/73	1	55	24	377	130	145	123	102	126	1.90			5	27

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m^3	EXTREMES MAX OBS ug/m^3	QUARTERLY MEANS ug/m^3 1	2	3	4	ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3 PRIMARY	STANDARDS ug/m^3 SECONDARY	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	# OBSERVATIONS GREATER THAN STANDARDS SECONDARY
WYOMING																
Casper	Total suspended particulates	1972	1	29	11	166	48	47	79	80	61	1.98	260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	2
		1971	1	26	13	255	44	71	97	120	77	1.94			1	3
		1970	1	26	23	128	44	70	84	39	57	1.62			0	0
		1969	1	25							61	1.71				
		1968	1	26	19	126	55	52	68	45	55	1.59			0	0
		1967	1	26	22	125					55	1.55				
	SO_2	6/72-6/73	15	64	0	16	4	2	2	2	2	3	365 (24 hr) 80(ann)		0	0
		1972	15	28	3	16	3	4	4	9	5	4			0	0
		1970	15	25	3	27	13	11	9	5	9	8			0	0
		1969	15	25	5	74	21	7	8	29	14	16				
		1968	15	26	3	28	11	8	10	9	9	5				
		1967	15	25	4	113	43	12	17	28	25	27				
	NO_x	1972	14	26	3	121	28	65	34	46	43	26	100(ann)	100(ann)		
		1971	14	24	15	247	51	39	112	70	68	60				
		1970	14	25	20	267	43	78	37	34	48	47				
		1969	14	26	23	111	47	49	54	35	47	20				
		1968	14	22	30	116	58	58	57	66	60	21				
Casper	Beryllium	1968	11	26	0	.0008	24 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Cadmium	1968	11	26	0	0	26 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Chromium	1968	11	26	0	.021	22 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					

SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES MIN OBS ug/m³	EXTREMES MAX OBS ug/m³	QUARTERLY MEANS ug/m³ 1	2	3	4	ANNUAL MEAN ug/m³	STANDARD DEVIATION ug/m³	STANDARDS PRIMARY ug/m³	STANDARDS SECONDARY ug/m³	# OBSERVATIONS GREATER THAN STANDARDS PRIMARY	SECONDARY
Casper	Cobalt	1968	11	26	.0	0	26 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Copper	1968	11	26	.05	.05	.05	.05	.05	.05	.05	.000				
		1969	11				.05	.22	.18	.07	.13					
	Iron	1968	11	26	.7	3.6	.7	.7	.7	.7	.7	.71				
		1969	11				.2	1.2	1.2	1.0	.9					
	Lead	1968	11	26	.04	.71	.17	.16	.17	.26	.19	.14				
		1969	11				.18	.73	.62	.54	.52					
	Manganese	1968	11	26	0	0	26 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Nickel	1968	11	26	0	.014	25 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Tin	1968	11	26	0	0	26 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Titanium	1968	11	26	0	0	26 samples below minimum detectable concentration									
		1969	11				0	0	0	0	--					
	Samarium	1968	11	26	.02	.02	.02	.02	.02	.02	.02	.00				
	Strontium	1968	11	26	.1	.4	.1	.1	.1	.1	.1	.1				
	Vanadium	1968	11	26	0	0	26 samples below minimum detectable concentration									
		1969	11				.0	.0	.009	0	--					
	Yttrium	1968	11	26	.001	.001	.001	.001	.001	.001	.001	.000				
	Fluoride ion	1970	3	26	.02	.11	.09	.09	.02	.02	.06	.03				
		1969	3	25	.02	.06	.03	.02	.02	.02	.03	.01				
		1968	3	26	.02	.02	.02	.02	.02	.02	.02	.00				
		1967	3	26	.02	.02	.02	.02	.02	.02	.02	.00				

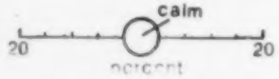
SITE	POLLUTANT	YEAR	SAMPLING-ANALYZING METHOD	# SAMPLES	EXTREMES ug/m^3		QUARTERLY MEANS ug/m^3				ANNUAL MEAN ug/m^3	STANDARD DEVIATION ug/m^3	STANDARDS ug/m^3		# OBSERVATIONS GREATER THAN STANDARDS	
					MIN OBS	MAX OBS	1	2	3	4			PRIMARY	SECONDARY	PRIMARY	SECONDARY
Casper	Ammonium ion	1970	13	26	.02	.30	.13	.18	.4	.4	.10	.08				
		1969	13	25	.02	.70	.5	.7	.33	.29	.19	.21				
		1968	13	26	.10	.20	.17	.10	.11	.12	.13	.05				
		1967	13	25	.02	.30	.11	.7	.9	.10	.09	.06				
	Nitrate ion	1970	6	26	.10	1.30	.31	.57	.80	.33	.51	.34				
		1969	6	25	.10	2.30	.70	.70	.94	.45	.71	.49				
		1968	6	26	.30	1.40	.60	.70	.63	.60	.63	.29				
		1967	6		.30	1.10	.42	.51	.76	.45	.54	.20				
	Sulfate ion	1970	5	26	2.4	6.9	4.6	5.0	5.4	3.8	4.7	1.2				
		1969	5	25	2.6	12.7	7.1	3.3	5.6	5.5	5.5	2.3				
		1968	5	26	2.1	8.2	3.1	3.0	5.0	3.2	3.6	1.6				
		1967	5	26	1.4	6.3	3.2	3.1	3.0	1.9	2.8	1.1				
	Ammonia	1969	16	25	28.	114.	52	74	41	43	52	20				
		1968	16	25	28	137	44	77	63	47	58	25				
		1967	16	25	10	71	25	33	43	44	36	14				
Ranch 50 mi. E. of Casper (background)	Total suspended particulates	1973	1	55	19	221	44	77	57	59	58		260 (24 hr) 75(ann)	150 (24 hr) 60(ann)	0	3
Gillette		6/72-6/73	1	48	20	190	37	52	97	80	73	1.73			0	2
Rock Springs		6/73-12/73	1	25	17	312	--	--	152	100	127	1.92			1	11
	SO_2	6/73-12/73		25	0	8					3	2.80				

FIGURE A-1. SURFACE WIND ROSES- DECEMBER, JANUARY, FEBRUARY*


Billings
1
Bismarck
4
Casper
3
Rapid City
9
North Platte
1

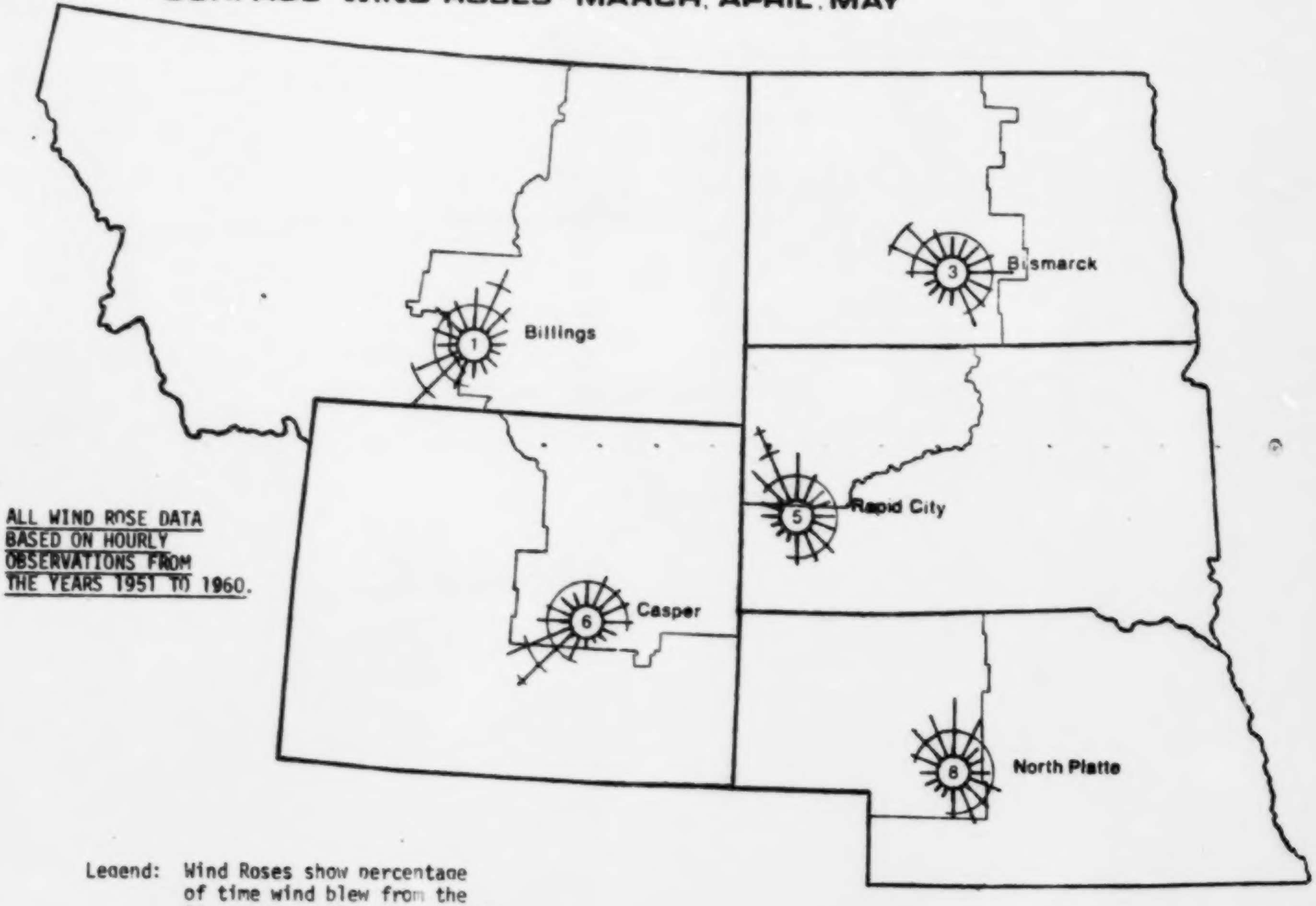
ALL WIND ROSE DATA
BASED ON HOURLY
OBSERVATIONS FROM
THE YEARS 1951 TO 1960.

Legend: Wind Roses show percentage of time wind blew from the 16 compass points or was calm.


calm
20
20
percent

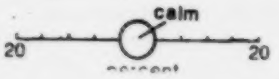
*Computed from monthly surface wind roses, Climatic Atlas of the United States, U. S. Dept. of Commerce. June, 1968

FIGURE A-2. **SURFACE WIND ROSES - MARCH, APRIL, MAY***


1
Billings
3
Bismarck
5
Rapid City
6
Casper
8
North Platte

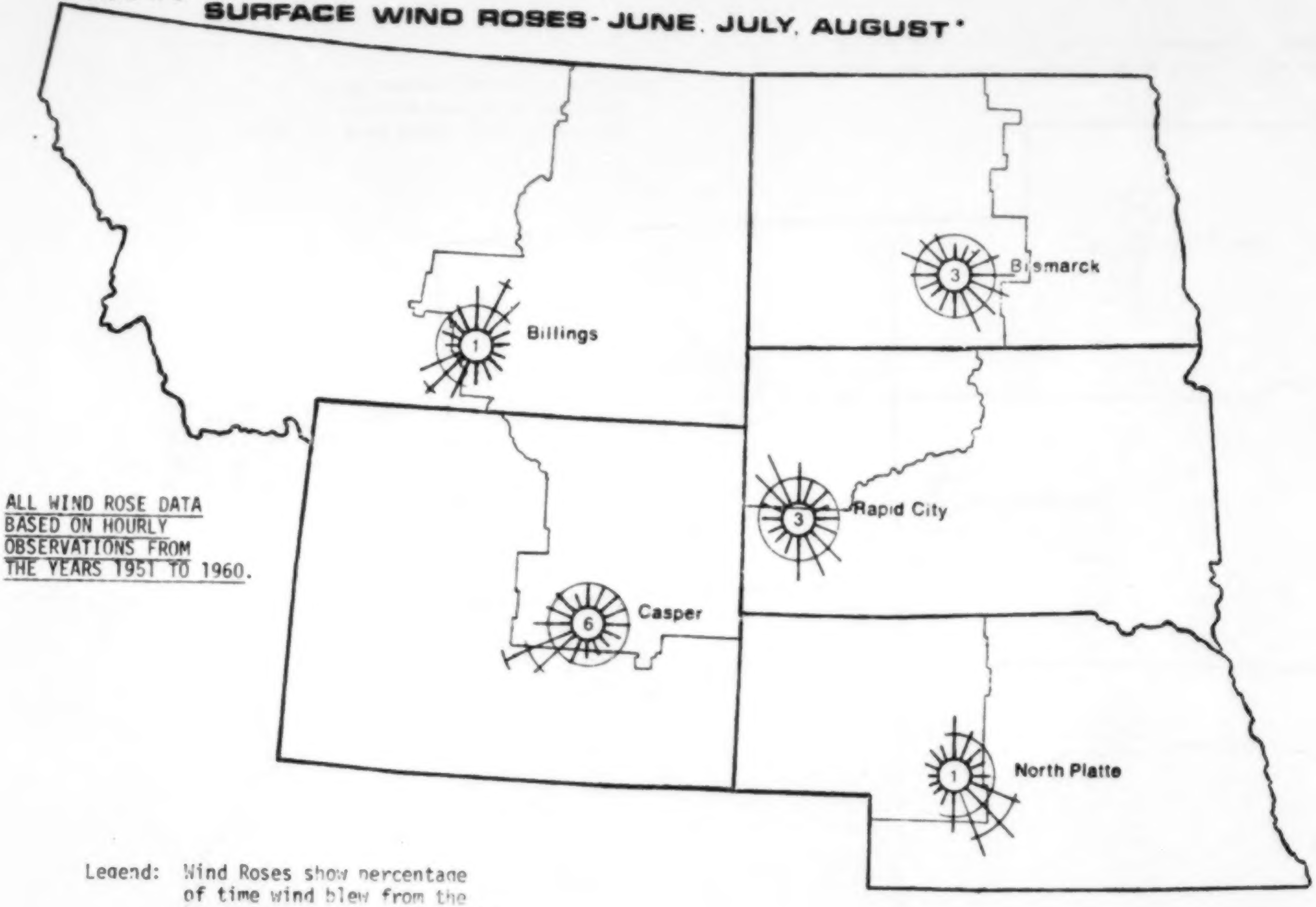
ALL WIND ROSE DATA
BASED ON HOURLY
OBSERVATIONS FROM
THE YEARS 1951 TO 1960.

Legend: Wind Roses show percentage of time wind blew from the 16 compass points or was calm.


calm
20
20
percent

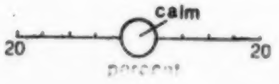
*Computed from monthly surface wind roses, Climatic Atlas of the United States, U. S. Dept. of Commerce. June, 1968

FIGURE A-3. **SURFACE WIND ROSES - JUNE, JULY, AUGUST***


1
Billings
3
Bismarck
3
Rapid City
6
Casper
1
North Platte

ALL WIND ROSE DATA
BASED ON HOURLY
OBSERVATIONS FROM
THE YEARS 1951 TO 1960.

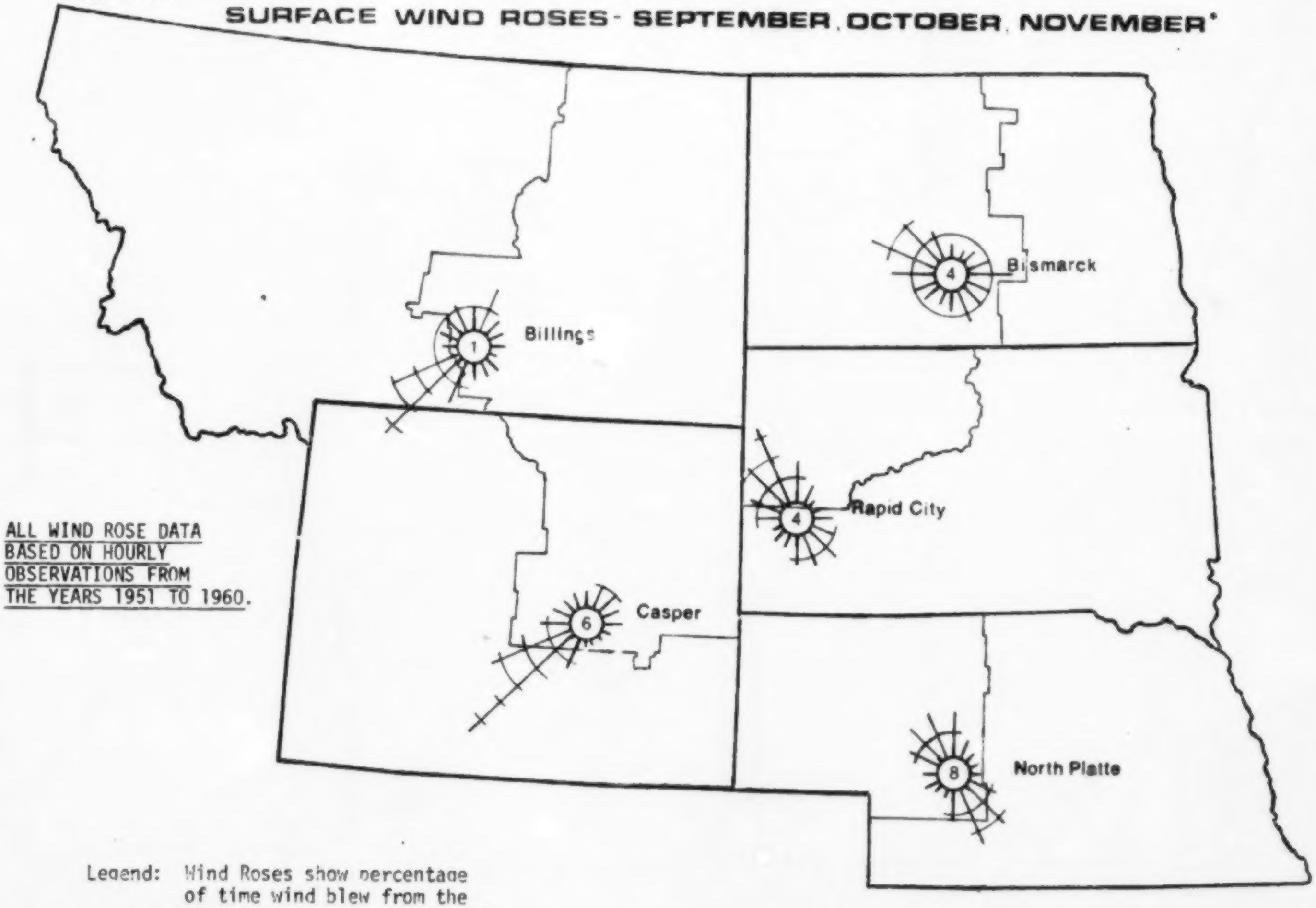
Legend: Wind Roses show percentage of time wind blew from the 16 compass points or was calm.


calm
20
20
percent

*Computed from monthly surface wind roses, Climatic Atlas of the United States, U. S. Dept. of Commerce. June, 1968

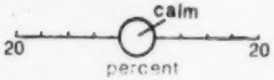
FIGURE A-4.

SURFACE WIND ROSES - SEPTEMBER, OCTOBER, NOVEMBER*


Billings
1
Bismarck
4
Rapid City
4
Casper
6
North Platte
8

ALL WIND ROSE DATA
BASED ON HOURLY
OBSERVATIONS FROM
THE YEARS 1951 TO 1960.

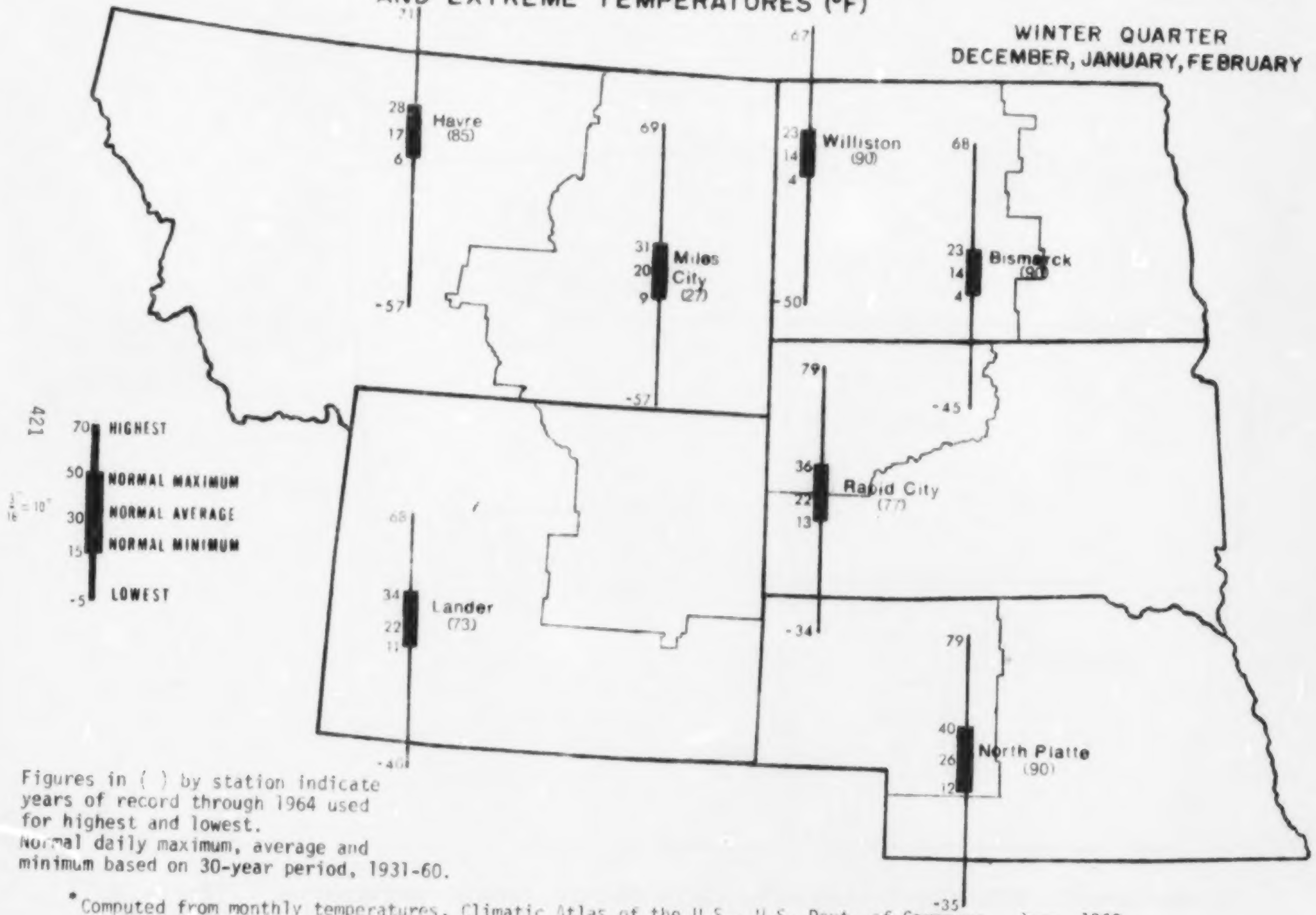
Legend: Wind Roses show percentage of time wind blew from the 16 compass points or was calm.


calm
20
20
percent

*Computed from monthly surface wind roses, Climatic Atlas of the United States, U. S. Dept. of Commerce. June, 1968

FIGURE A-5. NORMAL DAILY MAXIMUM, AVERAGE, MINIMUM AND EXTREME TEMPERATURES (°F)*

WINTER QUARTER
DECEMBER, JANUARY, FEBRUARY

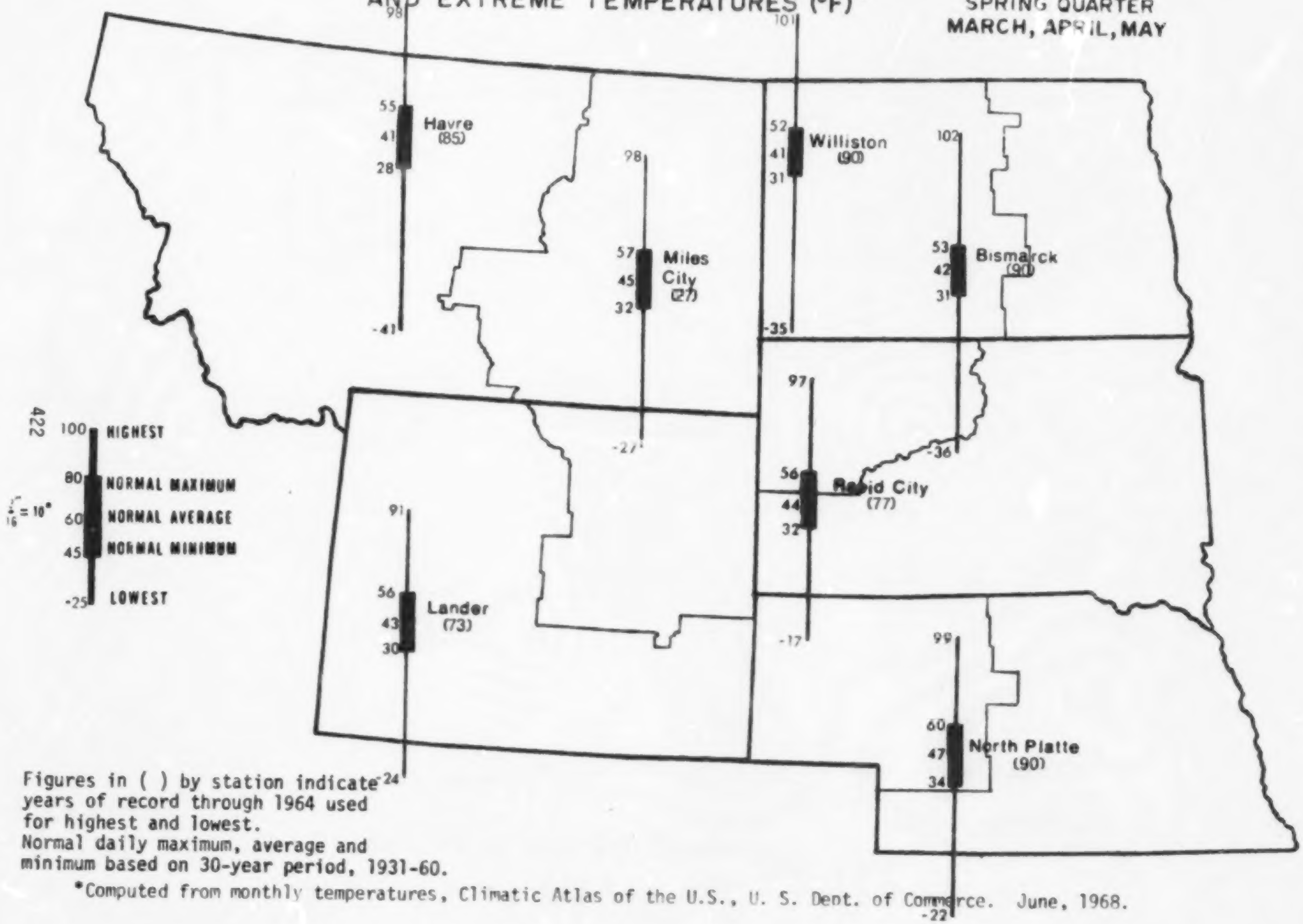

71
28
17
6
-57
Havre
(85)
69
31
20
9
-57
Miles City
(27)
67
23
14
4
-50
Williston
(90)
68
23
14
4
-45
Bismarck
(90)
79
36
22
13
-34
Rapid City
(77)
68
34
22
11
-40
Lander
(73)
79
40
26
12
-35
North Platte
(90)
70 HIGHEST
50 NORMAL MAXIMUM
30 NORMAL AVERAGE
15 NORMAL MINIMUM
-5 LOWEST
1/16" = 10°

Figures in ( ) by station indicate years of record through 1964 used for highest and lowest.
Normal daily maximum, average and minimum based on 30-year period, 1931-60.

*Computed from monthly temperatures, Climatic Atlas of the U.S., U.S. Dept. of Commerce. June, 1968.

FIGURE A-6. NORMAL DAILY MAXIMUM, AVERAGE, MINIMUM AND EXTREME TEMPERATURES (°F)*

SPRING QUARTER
MARCH, APRIL, MAY

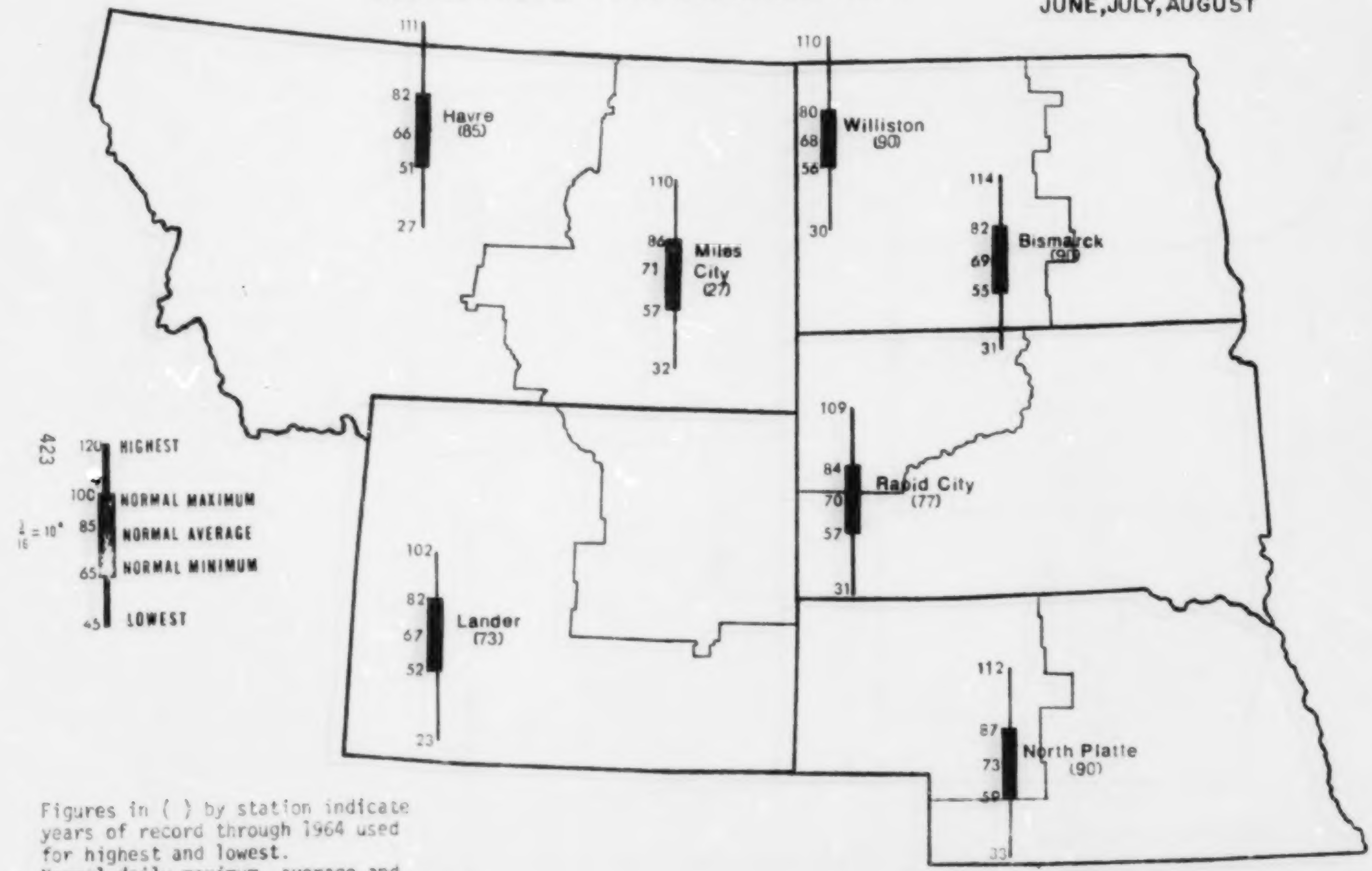

98
55
41
28
-41
Havre
(85)
98
57
45
32
-27
Miles City
(27)
101
52
41
31
-35
Williston
(90)
102
53
42
31
-36
Bismarck
(90)
97
56
44
32
-17
Rapid City
(77)
91
56
43
30
-24
Lander
(73)
99
60
47
34
-22
North Platte
(90)
100 HIGHEST
80 NORMAL MAXIMUM
60 NORMAL AVERAGE
45 NORMAL MINIMUM
-25 LOWEST
1/16" = 10°

Figures in ( ) by station indicate years of record through 1964 used for highest and lowest.
Normal daily maximum, average and minimum based on 30-year period, 1931-60.

*Computed from monthly temperatures, Climatic Atlas of the U.S., U. S. Dept. of Commerce. June, 1968.

FIGURE A-7. NORMAL DAILY MAXIMUM, AVERAGE, MINIMUM AND EXTREME TEMPERATURES (°F)*

SUMMER QUARTER
JUNE, JULY, AUGUST

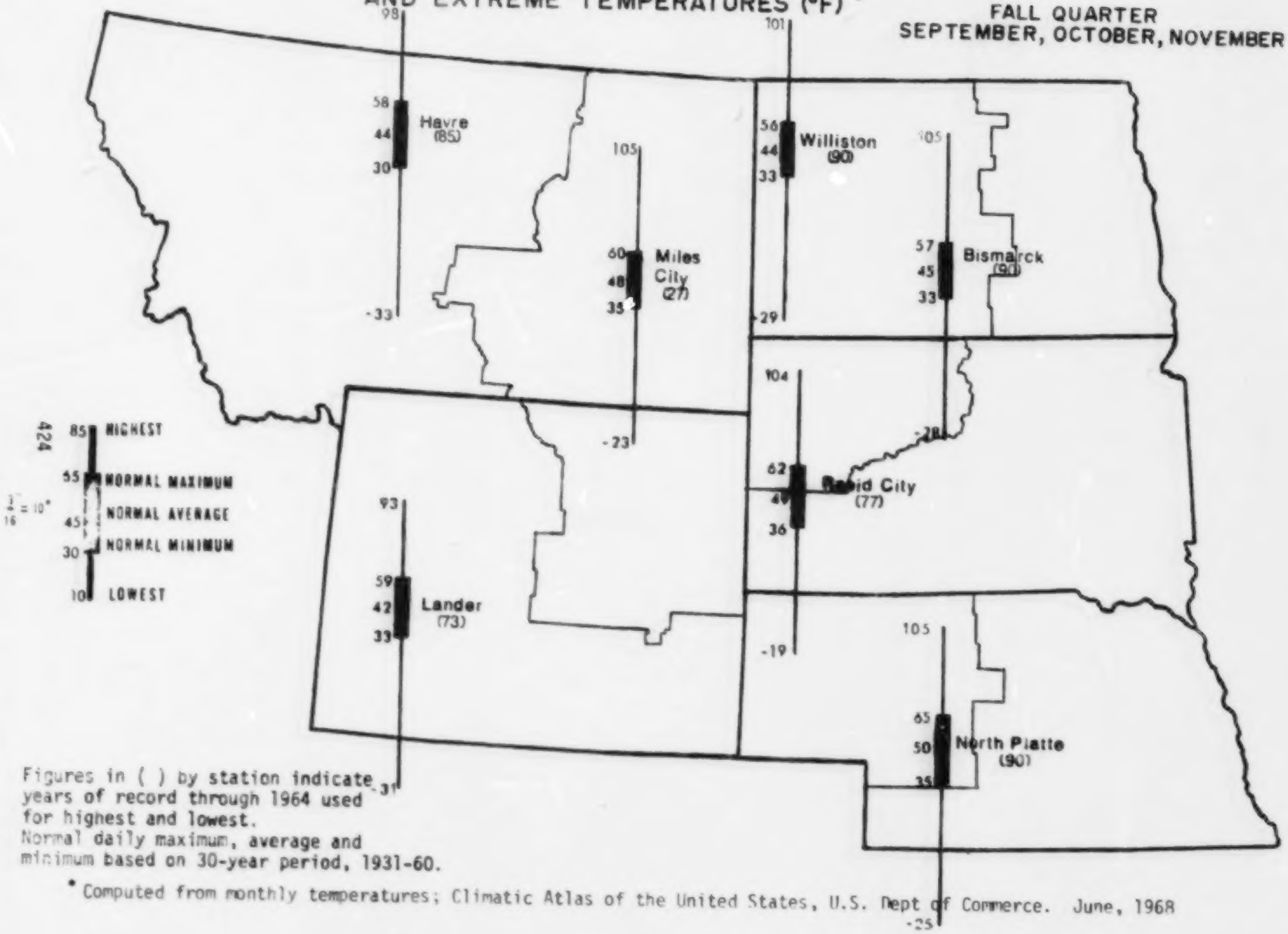

111
82
66
51
27
Havre
(85)
110
86
71
57
32
Miles City
(27)
110
80
68
56
30
Williston
(90)
114
82
69
55
31
Bismarck
(91)
109
84
70
57
31
Rapid City
(77)
102
82
67
52
23
Lander
(73)
112
87
73
59
33
North Platte
(90)
120 HIGHEST
100 NORMAL MAXIMUM
85 NORMAL AVERAGE
65 NORMAL MINIMUM
45 LOWEST
1/16 = 10°

Figures in ( ) by station indicate years of record through 1964 used for highest and lowest.
Normal daily maximum, average and minimum based on 30-year period, 1931-60.

*Computed from monthly temperatures; Climatic Atlas of the United States, U.S. Dept. of Commerce, June, 1968

FIGURE A-8. NORMAL DAILY MAXIMUM, AVERAGE, MINIMUM AND EXTREME TEMPERATURES (°F) *

FALL QUARTER
SEPTEMBER, OCTOBER, NOVEMBER



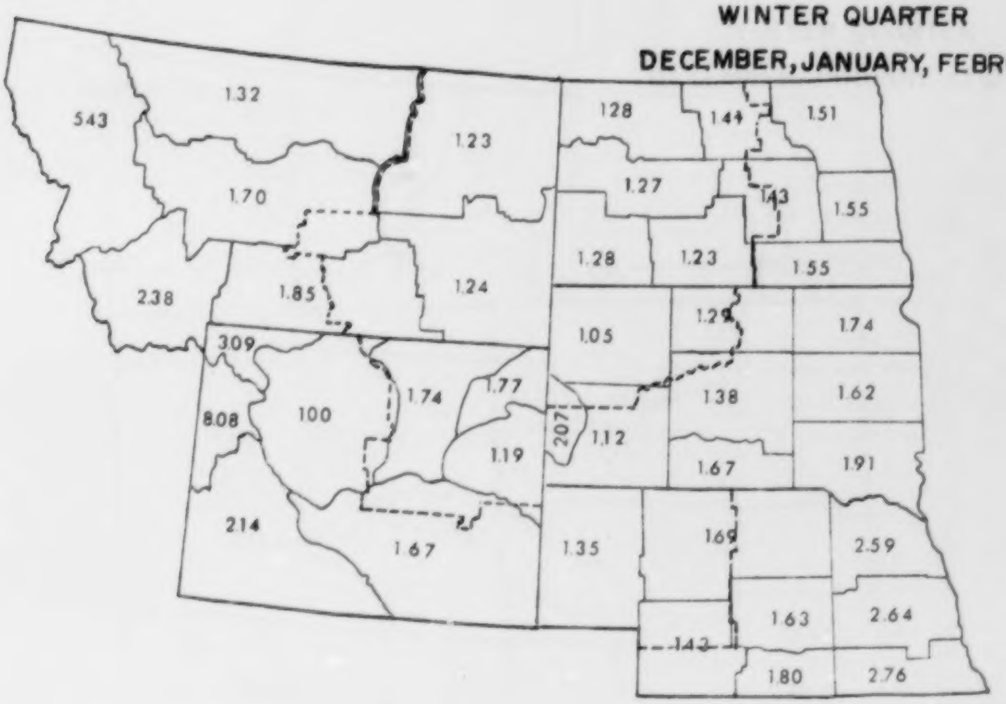
Havre (85)
98
58
44
30
-33
Miles City (27)
105
60
48
35
-23
Williston (90)
101
56
44
33
-29
Bismarck (90)
105
57
45
33
-28
Rapid City (77)
104
62
49
36
-19
Lander (73)
93
59
42
33
-31
North Platte (90)
105
65
50
35
-25
85 HIGHEST
55 NORMAL MAXIMUM
45 NORMAL AVERAGE
30 NORMAL MINIMUM
10 LOWEST
3/16" = 10°

Figures in ( ) by station indicate years of record through 1964 used for highest and lowest.
Normal daily maximum, average and minimum based on 30-year period, 1931-60.

* Computed from monthly temperatures; Climatic Atlas of the United States, U.S. Dept of Commerce. June, 1968

FIGURE A-9

MEAN PRECIPITATION
(inches) BY STATE CLIMATIC DIVISIONS*


543
1.32
1.23
128
1.44
1.51
1.70
1.27
1.43
1.55
1.28
1.23
1.55
2.38
1.85
1.24
1.05
1.29
1.74
309
1.74
1.77
8.08
100
1.38
1.62
207
1.12
1.19
1.67
1.91
214
1.67
1.35
169
2.59
1.63
2.64
143
1.80
2.76

WINTER QUARTER
DECEMBER, JANUARY, FEBRUARY

Based On 24 Years Of Data

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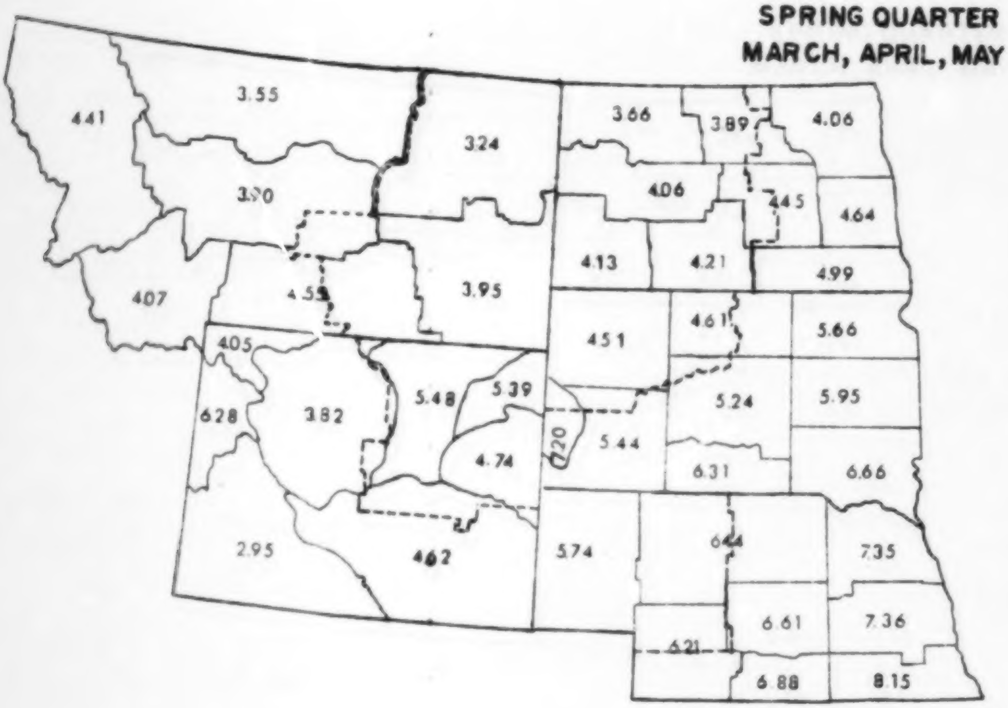
* Computed from monthly precipitation, Climatic Atlas of the United States, U.S. Dept. of Commerce. June, 1968.

FIGURE A-10

MEAN PRECIPITATION
(inches) BY STATE CLIMATIC DIVISIONS*


SPRING QUARTER
MARCH, APRIL, MAY
4.41
3.55
3.24
3.90
4.07
4.55
3.95
3.66
3.89
4.06
4.06
4.45
4.64
4.13
4.21
4.99
4.05
6.28
3.82
5.48
5.39
4.74
7.20
4.51
4.61
5.66
5.24
5.95
5.44
6.31
6.66
2.95
4.62
5.74
6.44
7.35
6.61
7.36
6.21
6.88
8.15

Based On 24 Years Of Data

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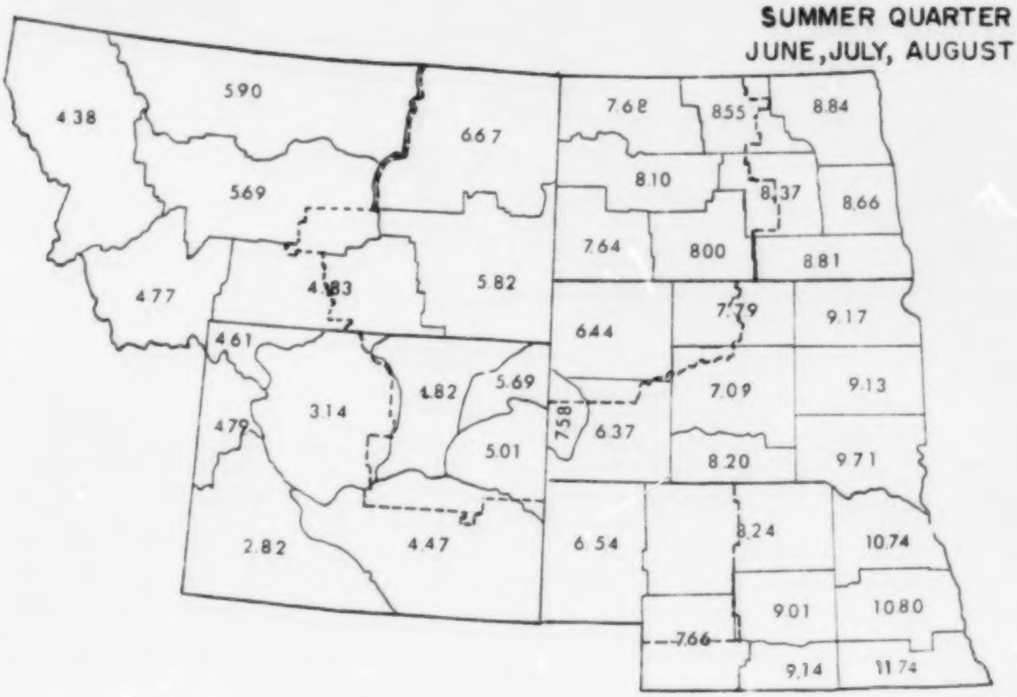
* Computed from monthly precipitation, Climatic Atlas of the United States, U.S. Dept. of Commerce. June, 1968.

FIGURE A-11

MEAN PRECIPITATION
(inches) BY STATE CLIMATIC DIVISIONS*


SUMMER QUARTER
JUNE, JULY, AUGUST
4.38
5.90
6.67
7.68
8.55
8.84
5.69
8.10
8.37
8.66
7.64
8.00
8.81
4.77
4.83
5.82
6.44
7.79
9.17
4.61
3.14
4.82
5.69
7.58
6.37
7.09
9.13
4.79
5.01
8.20
9.71
2.82
4.47
6.54
8.24
10.74
9.01
10.80
7.66
9.14
11.74

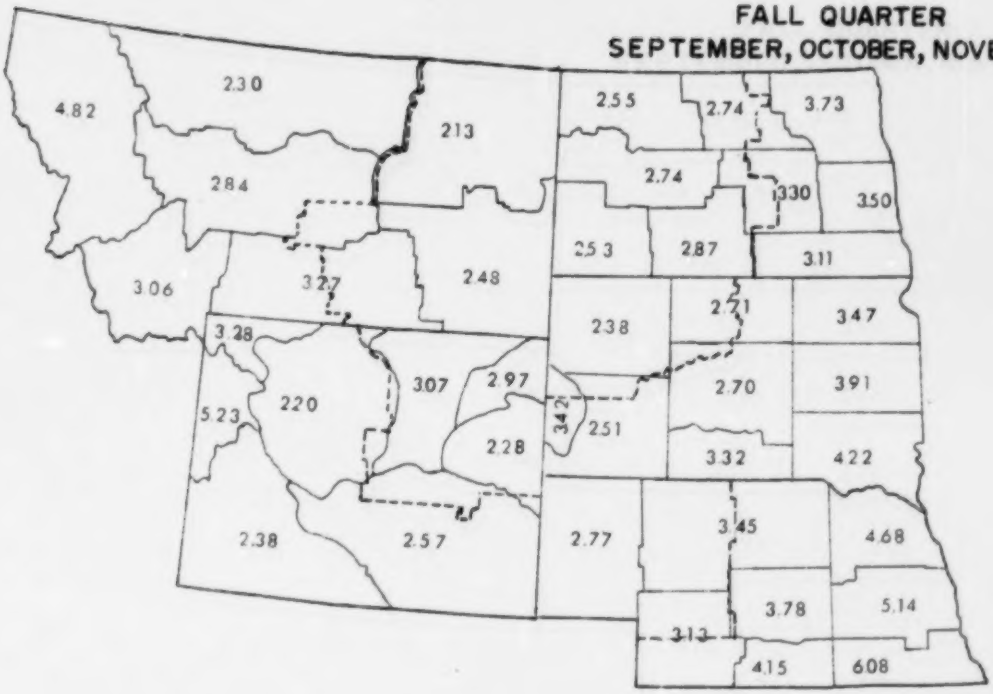
Based On 24 Years Of Data

---

* Computed from monthly precipitation, Climatic Atlas of the U.S., U.S. Dept. of Commerce. June, 1968.

FIGURE A-12

PRECIPITATION
(inches) BY STATE CLIMATIC DIVISIONS*



4.82
2.30
213
2.84
3.06
327
2.48
2.55
2.74
3.73
2.74
330
350
25 3
2.87
3.11
238
2.71
347
3.28
220
5.23
307
2.97
342
2.51
2.70
391
2.28
3.32
422
2.38
2.57
2.77
3.45
4.68
3.78
5.14
3.13
4.15
608

FALL QUARTER
SEPTEMBER, OCTOBER, NOVEMBER

Based On 24 Years Of Data

*Computed from monthly precipitation, Climatic Atlas of the United States, U.S. Dept. of Commerce. June, 1968.